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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Revise its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 16-06-013 (Filed June 30, 2016)

PACIFIC GAS AND ELECTRIC COMPANY'S (PG&E) AGRICULTURAL BALANCING ACCOUNT STUDY WITH AGRICULTURAL PARTIES' ADDENDUM

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Dated: September 23, 2016

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In compliance with Decision (D.) 15-08-005, Pacific Gas and Electric Company (PG&E) hereby provides the California Public Utilities' Commission (Commission or CPUC) and all parties to its 2017 General Rate Case (GRC) Phase II proceeding (Application 16-06-013), the Agricultural Balancing Account Study (AG Report), with Addendum from agricultural parties.

This filing also complies with the August 30, 2016 letter from Timothy Sullivan, the CPUC's Executive Director, granting PG&E's request for a scheduling extension to serve the AG Report, in order to allow intervenors who wished to include their own comments, as an addendum to this Report. The AG Report and Addendum filed herewith constitute Appendix F to Exhibit (PG&E-1), Prepared Testimony, Volume 2.

Respectfully submitted,

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By: */s/Gail L. Slocum*
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APPENDIX F

(As Filed in Exhibit 1)

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

AGRICULTURAL CLASS BALANCING ACCOUNT STUDY

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
AGRICULTURAL CLASS BALANCING ACCOUNT STUDY

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
AGRICULTURAL CLASS BALANCING ACCOUNT STUDY

A. Introduction

In the Marginal Cost and Revenue Allocation Settlement (the Settlement) approved by Decision 15-08-005, the California Public Utilities Commission (CPUC or Commission) approved an Agricultural Class Balancing Account Study. The description of the study as set forth in the Settlement is provided:

> A balancing account or other mechanism that addresses the high level of sales variability and sales forecast uncertainty pertaining to the agricultural class, principally as a result of the unpredictability of the availability of surface water, will not be established as part of this Settlement. Instead, parties agree to pursue additional analyses to examine the desirability of such a balancing account, and the necessary components to develop it. Such analyses would review the year-to-year volatility of agricultural class revenues and sales versus other customer class revenues and sales, and include an assessment of possible over-collections of agricultural class revenue that accounts for variation in both PG&E's cost of service and revenues collected due to agricultural sales variability.
>
> PG&E will compile an initial set of data based on input the parties provide to PG&E during the first quarter of 2015, and will provide that data to interested parties, to the extent feasible, for review at least two weeks prior to a workshop at which the data will be discussed. At the workshop, which is to be held no later than 9 months prior to the next GRC Phase II application deadline (and which may be held earlier), the parties will review the available data, provide input with regard to the required analysis, and establish a schedule for completion of the analysis and a workshop report. The schedule will set a date by which PG&E will complete and provide to all parties a report memorializing the analysis, which is targeted to be provided to interested parties no later than 6 months prior to the filing of PG&E's next GRC Phase II application (and which may be provided earlier). The schedule will also include a second workshop at least two weeks following distribution of the report, at which parties will have the opportunity to ask questions about the report and discuss PG&E's analysis and conclusions. The schedule will afford parties an opportunity to provide their own evaluation of the analysis, to be transmitted to PG&E within 6 weeks of service of the initial report, such that evaluations by the parties can be included with the report. The parties envision the completion of the whole agricultural balancing account analysis process by no later than 4 months in advance of the deadline for PG&E's 2017 GRC Phase II application. The report will be included as a compliance item attached to PG&E's next GRC Phase II application.

In response to Pacific Gas and Electric Company's (PG&E) request for data requirements, Agricultural Parties[1] and the California Large Energy Consumers Association (CLECA) provided requests for information. PG&E responded to the Agricultural Parties request on September 4, 2015, and to CLECA's request on September 11, 2015. A summary of these data requests is provided as Attachment 1 to this Appendix. PG&E held the first workshop specified by the Settlement on September 22, 2015.[2] The notice regarding the availability of the Draft Report was issued on November 30, 2015.[3] Comments on the Draft Report were received from the Agricultural Parties on December 14, 2015.[4] PG&E issued a revised Draft Report on December 17, 2015, which provided non-substantive edits to the original Draft Report primarily to ensure common use of terms in preparation for the second workshop.[5] The second required workshop was held December 21, 2015.[6] During the workshop, the parties requested a summary be prepared of the discussion. PG&E prepared a draft summary and requested comments on the summary. The summary of the second workshop is incorporated into Section C below.

B. Workshop 1, September 22, 2015

On September 22, 2015, PG&E held the first workshop on the AG Balancing Account Study. Southern California Edison Company (SCE), AECA, CLECA, CFBF and PG&E participated in the workshop. PG&E's presentation, as well as the presentation made by AECA, is attached to this Report as Attachment 3. Three additional areas of work were discussed during the meeting for consideration in the Report.

1. Average rate variability was not mentioned during PG&E's presentation and should be included in the study. PG&E agrees with this observation and has incorporated that work into this study.

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1 Agricultural Parties include California Farm Bureau Federation (CFBF) and Agricultural Energy Consumers Association (AECA).

2 Required notice was provided for the first workshop on August 31, 2015.

3 By the Executive Director's letter dated November 6, 2015, the due date of the draft Study was extended to November 30, 2015.

4 Comments from CLECA were also received verbally.

5 A list of terms is provided as Attachment 2 to this Report.

6 Required notice for the second workshop was provided on December 9, 2015.

2. Actual costs for agriculture for 2014 were requested. As a general matter, very few utility costs are recorded by customer class. The exception would be some portion of customer-related costs that are often captured by rate schedule. As such, there is no way to produce an 'actual' accounting of cost by rate schedule.
3. PG&E was requested to provide an approach to address under or over-collections that may be identified by this Report.

C. Workshop 2, December 21, 2015

PG&E, the Office of Ratepayer Advocates (ORA), CLECA, CFBF, SCE and AECA participated in the second Agricultural Class Balancing Account Workshop on December 21, 2015.

PG&E introduced the second workshop as an opportunity to ask questions about the Draft Report prepared by PG&E. Prior to the workshop, AECA and CFBF provided comments on the Draft Report. PG&E discussed these comments with AECA and CFBF prior to the workshop, and briefly reviewed that discussion with the parties. In brief, AECA and CFBF felt that while Tables 4 and 5 of the Draft Report were a good start, the following tables (Tables 6 to 11), which were intended only to reflect the allocation of a change in systemwide revenue requirement based on the current allocation rules (i.e., using the actual revenue allocation in a given year), needed to be revised to also reflect the change in that year's revenue allocation that would ensue from using an underlying General Rate Case (GRC) Phase II revenue allocation that reflected perfect forecast conditions. The parties also were concerned that the latter set of tables did not use the same years (2011 and 2013) as the former (2011 and 2014), making comparisons difficult.

In discussing how the "perfect forecast" GRC Phase II revenue allocation might be reflected in the revenue allocation in each year of the GRC cycle, CLECA asked if it would be possible to make an adjustment to agricultural rates each year once water availability becomes known to reflect its impact on forecast agricultural sales. If a revision were determined to be mechanically possible, then a discussion of what adjustments might be fair and reasonable could continue. PG&E tentatively agreed that an adjustment with the following characteristics would be mechanically feasible:

1. A publically acknowledged trigger indicating the level of water availability, and thus greater or reduced water pumping needs, would be known by about mid-March. A specific trigger value would dictate a specific adjustment to agricultural rates that could then be implemented on May 1 by Tier 1 advice letter.
2. The exact nature of the specific adjustment to agricultural rates was not defined; however, higher pumping needs resulting from reduced water availability would result in lower agricultural rates. Similarly, greater water availability, and thus lower agricultural water pumping needs, would lead to higher agricultural rates.
3. The adjustment to agricultural rates would need to be transparent and non-controversial to enable implementation via a Tier 1 advice letter.
4. The adjustment would impact only agricultural rates and would not affect rates for any other class.
5. The adjustment and PG&E's forecast need to be in sync. That is, if the forecast already implied a year of scarce water availability, a duplicative adjustment to agricultural rates would not be appropriate.

AECA and CFBF indicated that water delivery allocations are usually announced by mid-March by the State Water Project and Central Valley Project. These would provide the trigger on forecasting agricultural demand for the coming summer.

None of the parties objected to investigating the adjustment described above, but ORA, CLECA, AECA, and CFBF indicated that further detail was required before any agreement could be reached. With the understanding that an adjustment to rates might be feasible, PG&E agreed to look into whether a "perfect-forecast"-based allocation could be completed on a consistent basis for the period 2011 through 2014 for generation and distribution revenue. This analysis would be used to determine what adjustments might be appropriate.

D. Sales and Average Rate Variability

1. Sales Variability

In **Table 1** of Attachment 4, the total sales <u>forecast</u> and the total <u>actual</u> sales are compared for the period beginning 1995. The classes used for this comparison are categorized by Revenue Account and comprise 98 to

99 percent of the total forecast sales each year. The comparison by Revenue Account is used because sales are actually forecasted by revenue account. As discussed at the time the study was formulated, the agricultural class has demonstrated significantly more sales variability relative to forecast than have other customer classes.

The most impacted years where total agricultural sales were forecasted at levels less than actual were 2008, 2009, 2013 and 2014. In general, years where there was a forecast of levels greater than actual indicated less variation relative to the total agricultural forecast sales and occurred in 2005 and 2011.

2. Average Rate Variability

The purpose of this analysis was to compare the bundled forecast and bundled actual average rate by customer class. PG&E's sales forecast each year is determined in the Energy Resource Recovery Account (ERRA) proceeding and is used to set rates in the following year. In addition to the overall forecast of agricultural sales developed in the ERRA proceeding, the forecast average rate depends on the estimate of individual billing determinants for each rate schedule. For example, the forecast average rate would be a function of estimated sales by Time-of-Use (TOU) period, customer months, maximum or connected demand, and where relevant, demand by TOU period. These forecast billing determinants are derived based on average recorded data for each class (using three years of recorded data for Agricultural schedules and one year for other schedules). Forecast billing determinants when applied to forecast sales and current rates determines the estimate of revenue at present rates from which class average rates are derived.

Table 2 of Attachment 4 includes a comparison of the bundled average agricultural rate (forecast and actual) to the system average bundled rate (forecast and actual). Because of the variation in agricultural average rates (forecast compared to actual), PG&E made a comparison of the bundled average rates for all customer groups from 2005 through 2014. **Table 3** of Attachment 4 provides a comparison of average bundled rates for all customer groups. For bundled average forecast rates, PG&E used January 1 (Annual Electric True-Up) rates for each year. In the Agricultural

Class, AG-ICE revenue is separately identified in recorded information, but is not forecast. The Standby and AG-A populations demonstrate the most variation in bundled average rate in every year.

E. Generation and Distribution Cost of Service

As a result of comments regarding PG&E's draft report, PG&E agreed to look into developing cost of service on a consistent basis for the period 2011 through 2014 for generation and distribution revenue. This section of the report deals with that assessment. The purpose of this review is to determine the impact of variation of actual agricultural sales compared to forecast as those differences could affect the allocation of cost to the agricultural class. Since PG&E's forecast of sales is the basis for determining the rates charged to customers and by extension the actual billed revenue, this comparison can be made by a comparison of the actual billed revenue to the revenue that would have otherwise been allocated to customers and billed if a full cost-based allocation was performed each year.

PG&E analyzed the generation and distribution cost of service by preparing a cost-based <u>revenue allocation</u> to the class as if they were prepared for a GRC Phase II proceeding. However, for this comparison, PG&E developed the revenue allocation for specified years utilizing assumptions for the actual year (i.e., a <u>perfect forecast</u>) and compared those results with the actual billed revenue. This comparison focuses on distribution and generation allocations of cost since those are the costs driven by the marginal cost ratemaking in the Phase II proceedings. PG&E has evaluated the period from 2011 (a relatively wet year where forecast agricultural sales lower than forecast) through 2014 (a drought year where total agricultural sales were significantly higher than forecast) for purposes of the analysis.

1. Generation Allocation

Generation revenue is allocated to each customer class based on its share of marginal cost revenue. Generation marginal cost revenue is fundamentally comprised of two parts. First, marginal generation capacity cost revenue is determined by multiplying a generation marginal capacity cost by Peak Cost Allocation Factors (PCAF), which are estimates of each customer class's contribution to the system peak hours. The second portion of generation marginal cost is marginal energy costs (MEC). MECs are determined for each time period and then multiplied by the TOU sales for each class to determine the MEC revenue. The sum of generation marginal capacity cost revenue and MEC revenue are the total generation marginal cost revenue for the class. Total generation revenue is then allocated to each customer class in proportion to its share of marginal cost revenue. This approach is known as the Equal Percent of Marginal Cost (EPMC) method.

Typically in GRC Phase II proceedings, recorded base year data is used to develop cost of service for the forecasted test year. For this analysis, however, actual data for sales and PCAFs were available for each year to allow a full study based on the actual sales and loads for each year, effectively permitting a forecast equal to actual sales in the test year. To develop the cost of service for each year, PG&E used PCAFs from 2011 for 2011, PCAFs from 2012 for 2012, PCAFs for 2013 for 2013, and PCAFs from 2014 for 2014. Similarly, actual total sales from each year were used as the forecast for that same year.[7]

PG&E first conducted the analysis for all four years using PG&E's proposed generation marginal costs as presented in its 2014 GRC Phase 2 proceeding as shown in Table F-1 below. The subsequent Tables F-2 through F-6 are based on this 2014 GRC marginal cost. However, PG&E has also conducted the analysis based on its proposed 2011 GRC marginal generation costs as described below.

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7 Total billed sales were used for the analysis. Usage by TOU period and PCAFs are based on the Load Research Study results for each year.

TABLE F-1
2014 MARGINAL GENERATION COSTS

Line No.		Marginal Energy Costs ($/kWh) Transmission	Primary	Secondary
1	Summer On Peak	$0.05613	$0.05718	$0.06001
2	Summer Part Peak	$0.04791	$0.04881	$0.05123
3	Summer Off Peak	$0.03654	$0.03722	$0.03907
4	Winter Part Peak	$0.04856	$0.04948	$0.05192
5	Winter Off Peak	$0.03968	$0.04043	$0.04243
		Generation Marginal Capacity Cost ($/kW-year) including 15% Reserve Adder		
		Transmission	Primary	Secondary
6	Average Cost	$65.65	$67.58	$71.63

Next, generation marginal cost revenues were derived for each year using the marginal costs from Table F-1 and recorded sales and loads. The marginal cost revenue divided by the bundled sales is equal to the average marginal cost. Table F-2, below, shows the average generation marginal cost revenue for capacity and energy.

TABLE F-2
AGRICULTURAL CLASS GENERATION MARGINAL COST OF SERVICE

Line No.		Recorded Bundled Sales	Average Capacity MC	Average Energy MC	Total Average MC	Total Marginal Cost Revenue
		(GWh)	($/kWh)	($/kWh)	($/kWh)	($M)
1	2011	4,654	0.01854	0.04520	0.06373	297
2	2012	6,140	0.01711	0.04517	0.06228	382
3	2013	6,984	0.01434	0.04508	0.05942	415
4	2014	7,582	0.01422	0.04584	0.06006	455

PG&E reviewed the cost drivers for cost of service calculation. As discussed above, the cost drivers were generation PCAFs and usage by TOU period. Generation PCAFs are expressed below as the agricultural percentage share of systemwide PCAFs in each year. As generally supporting the higher PCAF shares over time, PG&E notes that the agricultural peak period usage has increased relative to other customer groups over time (Table F-3, Column (5) below). However, as noted in

Table F-2, the average generation marginal cost has declined as a result of higher load factor (noted in Table F-3, Column (4) below).

TABLE F-3
AGRICULTURAL CLASS GENERATION CAPACITY COST DRIVERS

Line No.		Generation PCAF	System Generation PCAF Share	Bundled Sales	kWh/ PCAF-kW	Ratio of Agricultural Peak Sales to Total Peak Sales
		(MW)		(GWh)	(hrs)	
		(1)	(2)	(3)	(4)	(5)
1	2011	1,259	7.46%	4,654	3,696	6.20%
2	2012	1,532	9.32%	6,140	4,007	8.02%
3	2013	1,453	8.23%	6,984	4,808	9.19%
4	2014	1,505	9.05%	7,582	5,037	10.13%

TABLE F-4
AGRICULTURAL CLASS GENERATION ENERGY COST DRIVERS

Line No.		Summer			Winter		Annual
		On Peak	Part Peak	Off Peak	Part Peak	Off Peak	Total
		(%)	(%)	(%)	(%)	(%)	(%)
1	2011	12.5%	14.3%	37.4%	14.9%	20.9%	100.0%
2	2012	12.3%	14.4%	37.5%	14.9%	20.9%	100.0%
3	2013	11.0%	15.4%	37.8%	15.6%	20.2%	100.0%
4	2014	11.7%	14.5%	38.5%	14.7%	20.5%	100.0%

PG&E determined the total cost allocation for each year based on the marginal cost revenue for each year, using 2014 marginal costs throughout. This allocated revenue is the target level of revenue for the class adjusted for the EPMC multiplier. The target revenue is determined by multiplying the total billed generation revenue for the year by the agricultural class share of marginal cost revenue.

TABLE F-5
ALLOCATED GENERATION REVENUE

Line No.		Agricultural Class Generation Marginal Cost	Total Generation Marginal Cost	Agricultural Marginal Cost Share	Total Billed Generation Revenue	Allocated Agricultural Generation Revenue
		($M)	($M)	(%)	($M)	($M)
1	2011	297	4,653	6.37%	5,843	372
2	2012	382	4,680	8.17%	5,545	453
3	2013	415	4,754	8.73%	6,194	541
4	2014	455	4,617	9.86%	6,740	665

As a final step, the actual agricultural billed revenue is compared to the allocated revenue in the table below.

TABLE F-6
COMPARISON OF GENERATION ALLOCATED VERSUS BILLED REVENUE

Line No.		Allocated Agricultural Generation Revenue	Allocated Agricultural Generation Average Rate	Agricultural Billed Generation Revenue	Agricultural Billed Generation Average Rate	Generation Revenue Difference	Average Generation Rate Difference
		($M)	($/kWh)	($M)	($/kWh)	($M)	(%)
1	2011	372	$0.08005	334	$0.07173	(39)	(10.38)%
2	2012	453	$0.07379	425	$0.06922	(28)	(6.18)%
3	2013	541	$0.07742	502	$0.07189	(39)	(7.14)%
4	2014	665	$0.08768	601	$0.07925	(64)	(9.61)%

The step by step calculation provided in tables shown above is summarized in Table 1 of Attachment 5. PG&E next repeated the analysis using 2011 marginal costs for all four years: 2011 through 2014. These results are summarized in Table 2 of Attachment 5. PG&E's proposed 2011 generation marginal costs are shown in Table F-7, below.

TABLE F-7
2011 MARGINAL GENERATION COSTS

Line No.		Marginal Energy Costs ($/kWh) Transmission	Primary	Secondary
1	Summer On Peak	$0.04945	$0.05109	$0.05356
2	Summer Part Peak	$0.04632	$0.04780	$0.04919
3	Summer Off Peak	$0.03441	$0.03524	$0.03592
4	Winter Part Peak	$0.04512	$0.04633	$0.04859
5	Winter Off Peak	$0.03567	$0.03649	$0.03721
		Generation Marginal Capacity Cost ($/kW-year) including 15% Reserve Adder		
		Transmission	Primary	Secondary
6	Average Cost	$105.48	$108.97	$114.24

2. Distribution Allocation

Distribution revenue is also allocated to each customer class based on its share of marginal cost revenue. Distribution marginal cost revenue is comprised of two parts. The first part is distribution marginal customer access costs (MCAC) and the second part is the marginal distribution capacity cost (MDCC) portion of the rate. MCAC revenue is determined by multiplying the MCAC by the number of customers in the year. MDCC revenue is a function of two different kinds of distribution costs. The first kind are those which vary by time of day, or are time varying. For these costs, the marginal cost revenue is determined by multiplying a distribution PCAF by the primary MDCC. For the second type of cost which is not time varying, marginal cost revenue is determined by multiplying the new business primary MDCC and secondary MDCC by final line transformer (FLT) demand. The sum of distribution MCAC and the two types of MDCC revenues is the total distribution marginal cost revenue for the class. Total distribution revenue is then allocated to each customer class in proportion to its share of marginal cost revenue consistent with the EPMC method.

As for generation described above, typically in GRC Phase II proceedings, recorded base year data is used to develop cost of service for the forecasted test year. For this analysis, however, actual data was available for each year to allow a full study based on the actual customers, sales and loads for each year, effectively permitting a forecast equal to actual sales for the test year. To develop the cost of service for each year, PG&E developed and used distribution PCAFs from 2011 for 2011, PCAFs from 2012 for 2012, PCAFs for 2013 for 2013, and PCAFs from 2014 for 2014. Similarly, actual final line transformer demands from each year were used as the forecast for that same year.[8] Finally, PG&E used actual customer months for each year.

For purposes of this analysis, PG&E has not altered the distribution marginal capacity costs ($/kW FLT or $/kW PCAF) since these factors do not vary by customer class.[9] In addition, PG&E has not changed the MCAC from year to year.[10] PG&E first conducted the analysis for all four years using its proposed 2014 marginal costs, shown in Table F-8 below.[11] The subsequent Tables F-9 through F-12 are based on 2014 marginal costs. However, PG&E has also conducted the analysis based on its proposed 2011 marginal distribution costs as described below.

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8 Total billed sales were used for the analysis. Usage by TOU period and PCAFs are based on the Load Research Study results for each year.

9 While MDCC unit costs are the same for all customer groups, the average cost for a customer group can vary because these costs vary geographically.

10 MCAC can be determined by either the Rental Method or the New Customer Only (NCO) Method. The values used in this analysis were based on the NCO method, which is the approach PG&E has proposed in past GRCs. MCAC based on the NCO method can vary significantly for a single customer class because it is dependent on the number of forecast new connections for the group. Therefore, with substantially increasing or decreasing numbers of customers, the NCO method would result in a different unit MCAC. Because there is significant disagreement with regard to the merits of the NCO methodology, PG&E has not attempted to re-estimate the MCAC for customers based on the actual number of new connections from year to year.

11 The MDCC are derived and used in the revenue allocation process at the division level. They are summarized for comparison in Table 8 at the system level.

TABLE F-8
2014 MARGINAL DISTRIBUTION COSTS

Line No.	Marginal Capacity Costs ($/kW-year)	
1	Primary Distribution	$37.33
2	Secondary Distribution	$2.33
3	New Business	$11.26
	Marginal Customer Cost ($/Customer-month)	
4	Residential	$6.14
5	Agricultural A	$26.83
6	Agricultural B	$121.45
7	Small L&P	$26.95
8	A10 Medium L&P Secondary	$53.20
9	A10 Medium L&P Primary	$159.77
10	E19 Secondary	$62.34
11	E19 Primary	$524.08
12	E19 Transmission	$554.17
13	E20 Secondary	$463.31
14	E20 Primary	$557.35
15	E20 Transmission	$554.96
16	Streetlights	$6.92
17	Traffic Control	$8.83

Next, marginal cost distribution revenues were derived for each year. The marginal cost revenue divided by the bundled sales is equal to the average marginal cost. Table F-9, below, shows the separate components for each MDCC and MCAC revenue type for the Agricultural class.

TABLE F-9
AGRICULTURAL CLASS DISTRIBUTION MARGINAL COST OF SERVICE

Line No.		Recorded Bundled & DA/CCA Sales	Average Primary MC	Average Secondary MC	Average New Business MC	Subtotal Average MC	Average Customer MC	Total Average MC	Total Marginal Cost Revenue
		(GWh)	($/kWh)	($/kWh)	($/kWh)	($/kWh)	($/kWh)	($/kWh)	($M)
1	2011	4,691	0.00925	0.00124	0.00644	0.01693	0.01335	0.03027	142
2	2012	6,179	0.00730	0.00105	0.00565	0.01400	0.01031	0.02431	150
3	2013	7,022	0.00823	0.00109	0.00569	0.01501	0.00907	0.02408	169
4	2014	7,611	0.00961	0.00136	0.00627	0.01724	0.00902	0.02626	200

PG&E next reviewed the cost drivers used in the above cost of service calculation. As discussed above, the cost drivers were distribution PCAFs, FLT demand and numbers of customers which are shown in Table F-10, below.

TABLE F-10
AGRICULTURAL CLASS DISTRIBUTION COST DRIVERS

Line No.		Distribution PCAF (MW) (1)	Customer-months (2)	Bundled & DA/CCA Sales (GWh) (3)	FLT (MW) (4)	Average Agricultural Primary MDCC[(a)] $/PCAF kW
1	2011	1,530	1,009,599	4,691	3,970	42.64
2	2012	1,576	1,027,533	6,179	3,718	38.05
3	2013	1,616	1,026,492	7,022	4,012	41.20
4	2014	1,760	1,041,669	7,611	4,084	44.01

(a) Average Agricultural Primary MDCC is a weighted average of total Agricultural customers in each of the Divisions.

PG&E determined the Agricultural class's total cost allocation for each year based on the distribution marginal cost revenue for each year as shown in Table F-11. This allocated revenue is the target level of cost for the class. The target revenue is determined by multiplying the total billed distribution revenue for the year by the agricultural class share of marginal cost revenue.

TABLE F-11
ALLOCATED DISTRIBUTION REVENUE

Line No.		Agricultural Class Distribution Marginal Cost ($M)	Total Distribution Marginal Cost ($M)	Agricultural Marginal Cost Share (%)	Total Billed Distribution Revenue ($M)	Allocated Agricultural Distribution Revenue ($M)
1	2011	142	1,788	7.95%	3,572	284
2	2012	150	1,824	8.24%	4,012	330
3	2013	169	2,273	7.44%	4,035	300
4	2014	200	1,855	10.77%	3,398	366

As a final step, the recorded agricultural billed revenue is compared to the previously derived allocated revenue in the table below.

TABLE F-12
COMPARISON OF DISTRIBUTION ALLOCATED VERSUS BILLED REVENUE

Line No.		Allocated Agricultural Distribution Revenue	Allocated Agricultural Distribution Average Rate	Agricultural Billed Distribution Revenue	Agricultural Billed Distribution Average Rate	Distribution Revenue Difference	Average Distribution Rate Difference
		($M)	($/kWh)	($M)	($/kWh)	($M)	(%)
1	2011	284	$0.06050	212	$0.04521	(72)	(25.28)%
2	2012	330	$0.05349	281	$0.04556	(49)	(14.82)%
3	2013	300	$0.04276	300	$0.04270	–	(0.13)%
4	2014	366	$0.04810	306	$0.04020	(60)	(16.42)%

The step by step calculations for the tables shown above is summarized in Table 1 of Attachment 6. PG&E next repeated the analysis using its proposed 2011 marginal costs for all four years: 2011 through 2014. These results are summarized in Table 2 of Attachment 6. The distribution marginal costs used for 2011 through 2014 are shown in Table F-13, below.

TABLE F-13
2011 MARGINAL DISTRIBUTION COSTS

Line No.	Marginal Capacity Costs ($/kW-year)	
1	Primary Distribution	$54.86
2	Secondary Distribution	$0.77
3	New Business	$10.25
	Marginal Customer Cost ($/Customer-month)	
4	Residential	$7.64
5	Agricultural A	$42.14
6	Agricultural B	$68.56
7	Small L&P	$33.11
8	A10 Medium L&P Secondary	$136.86
9	A10 Medium L&P Primary	$80.20
10	E19 Secondary	$839.77
11	E19 Primary	$770.98
12	E19 Transmission	$1,335.26
13	E20 Secondary	$993.44
14	E20 Primary	$844.99
15	E20 Transmission	$1,999.29
16	Streetlights	$11.59
17	Traffic Control	$33.11

F. Revenue Allocation for Other Components of Rates

The purpose of this analysis is similar to the analysis of distribution and generation charges. Like those components, the objective is to compare the actual revenue and the revenue that would have been received if forecasts were perfect, that is if forecasted sales had actually equaled recorded sales. However, unlike distribution and generation, allocation of these costs is not based on marginal cost of service. In addition, all of these remaining components are collected from agricultural customers based on sales (i.e., $/kWh).[12] To study these components, PG&E utilized the same approach it used to allocate Nuclear Decommissioning in the Draft Report. One enhancement the parties requested was to provide this analysis over all four years, rather than 2011 and 2013 as originally studied. Accordingly, PG&E has supplemented its original analysis with additional data.

Specifically, for each year, PG&E has provided the following by customer class:

1) Forecast sales;
2) Forecast revenue based on total revenue requirement;
3) Actual sales;
4) Reallocated revenue based on actual sales and total revenue requirement; and
5) Revenue derived based on actual sales and adopted rate.

To make this comparison in both the Draft Report and for the current analysis, PG&E calculated the revenue for the year that would have been collected based on the actual sales and the rate that was in place on January 1 of each year which was derived based on a forecast of sales. PG&E uses this value as a proxy for the actual revenue. PG&E next calculated the revenue for each customer group using the actual sales as opposed to the forecast of sales used for the year.

---

[12] The following components are collected from agricultural customers in energy charges that do not vary by season or time of use: Transmission, Public Purpose Programs, Nuclear Decommissioning, the Energy Cost Recovery Amount, the New System Generation Charge (NSGC), the Department of Water Resources Bond Charge, and the Competition Transition Charge (CTC). Transmission charges are subject to Federal Energy Regulatory Commission jurisdiction. NSGC and CTC are not allocated based on marginal cost, but instead use load allocators called 12-month coincident peak (NSGC) and 100 peak hours (CTC). It would be a reasonable study enhancement to look at the 'perfect' allocation compared to the actual revenue from these two rate components.

In general, when a higher level of sales is assumed to collect the same amount of revenue, the average rate for the component is lower. Even though that higher level of sales may only be attributed to one customer class, the effect of perfectly forecast sales is to lower rates for all customer groups so that the correct revenue requirement is collected, assuming there is no change in cost. A comparison by class of forecast revenue based on the revenue requirement and forecast sales, forecast revenue requirement using actual sales (i.e., reallocated revenue) and revenue derived based on the actual sales and the adopted rate (which is a proxy for actual revenue) is provided in Attachment 7.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

ATTACHMENT 1

DISCOVERY

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
ATTACHMENT 1
DISCOVERY

First Data Request from the Agricultural Energy Consumers Association (AECA) and from the California Farm Bureau Federation, or the Agricultural Parties.

In response to Pacific Gas and Electric Company's (PG&E) request for data requirements, Agricultural Parties provided the following request. PG&E compiled the data response and provided it as AECA DR-007 on September 4, 2015.

> The Agricultural Parties recommend using the last 10 years of data (2005-2014) in order to provide for a long enough period to include various types of water and economic conditions while keeping the data collection and analysis manageable. The data needed for the analysis are as follows:
>
> 1. Hydrologic traces (i.e., annual water flows) for the major river basins (e.g. Four Rivers Index published by California Department of Water Resources);
>
> 2. Rainfall totals, comparable with those used PG&E's load forecasting model;
>
> 3. Forecasted kilowatt-hour (kWh) sales (total and bundled) adopted for each customer class in each GRC proceeding over the relevant period;
>
> 4. Forecasted kilowatt-hour (kWh) sales (total and bundled) adopted for each customer class in each ERRA proceeding over the relevant period;
>
> 5. Forecasted electric rate revenues adopted for each customer class and for the system total in each GRC Phase II proceeding over the relevant period, with generation and non-generation revenue requirements separately shown;
>
> 6. Actual kWh sales for each customer class in each year;
>
> 7. Actual electric rate revenues for each customer class in each year; and
>
> 8. Total system electric revenue requirement adopted for each year (in the Annual Electric True-Up or its equivalent), with ERRA generation and non-ERRA generation revenue requirements separately shown.

Data Request from the California Large Energy Consumers Association (CLECA)

In response to PG&E's request for data requirements, the California Large Energy Consumers Association (CLECA) provided the following request. For the period beginning 2004, data provided to AECA also satisfies the CLECA requirement. Information by class was provided for the period 1995 through 2004. PG&E compiled the data response and provided it as CLECA DR-012 on September 11, 2015.

CLECA believes that the comparison should be made over a long period (20 years) to take into account variations due to business cycles as well as weather cycles. We note that PG&E's FERC Form 1, page 304, states the recorded sales and revenues by rate schedule. We propose that PG&E compile 20 years of Form 1 data by rate schedule and for the same period produce the annual ERRA, or previously, ECAC forecasts for each customer class. With this set of data, we'd be able to see what kind of year-to-year variation occurs for each schedule over a long period. We would also be able to compare the recorded data to the forecast data at least by customer class so as to indicate the degree of forecast error that might be occurring.

Second Data Request From Agricultural Parties

Subsequent to the workshop, on September 30, 2015, AECA requested the following information. PG&E compiled the data response and provided it as AECA DR-008 on October 29, 2015.

For the General Rate Cases since the 2003 filing, provide the following:

a. marginal costs used for revenue allocation in the settlements by component, i.e., generation, distribution, customer services, by rate class;

b. EPMC scalers applied by component by rate class (likely the same for each rate class);

c. Transmission costs by rate class, and whether any scaler adjustments were made before being added to revenue requirements and retail rates; and

d. Other cost components explicitly included in the revenue allocation by rate class, e.g., nuclear decommissioning, public purpose programs, etc.

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
ATTACHMENT 2
DEFINITION OF TERMS

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
ATTACHMENT 2
DEFINITION OF TERMS

1. Average Rate – the average bundled total rate for a given class is the total revenue from bundled customers in that class divided by total bundled sales for that class. Similarly, the average generation rate is the generation revenue divided by bundled sales. The average rate for non-generation components, such as the average distribution rate, is total revenue for that component divided by total sales (including Direct Access/Community Choice Aggregation (DA/CCA)).
2. Actual (or Recorded or Billed) – actual/recorded/billed data refers to the amount of revenue, sales, load (Peak Cost Allocation Factors or Final Line Transformer demand) or billing determinants actually incurred for each year in question. Actual data may be total (including DA/CCA) or bundled (excluding DA/CCA).
3. Forecast – forecast data refers to the amount of revenue, sales or billing determinants forecasted for each year in question. Forecasted revenues (and rates) come from each year’s Annual Electric True-Up while sales and billing determinant forecasts come from each year’s Energy Resource Recovery Account proceeding. Forecast data may be total (including DA/CCA) or bundled (excluding DA/CCA), depending on purpose.
4. Perfect forecast – this report uses the term ‘perfect’ forecast to denote the forecast that would have been developed if the actual sales data for each class was known in advance and if standard methods were applied.
5. Revenue allocation – the process in which a total revenue requirement is divided between the classes. For General Rate Case allocations, distribution and generation revenue is typically allocated in proportion to marginal cost revenue.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

ATTACHMENT 3

PRESENTATIONS FROM WORKSHOP 1, SEPTEMBER 22, 2015

PG&E Agricultural Class Balancing Account Study

Presentation on behalf of the

Agricultural Energy Consumers Association

Presented by Richard McCann

M.CUBED

Statement of the Problem

- Agriculture is uniquely affected by variations in external factors beyond growers' control—i.e., water availability.
  - Electricity load varies more than any class as a result—up to ***32%*** from forecasted
- A review of historic revenue collection shows that on average the agricultural rate group has paid PG&E more than the projected revenue requirements assigned in each GRC.
- California is now in a record drought, and this overcollection is accruing to a substantial amount.
- What are the solutions given that droughts and floods cannot be readily forecasted?

M.CUBED

California's Record Drought

- The smallest Sierra snowpack on record with water content estimated at just 5 percent of long-term averages.
  - Reported as the driest in at least 500 years.
- More than two-thirds of the state is in an "extreme" drought, with more than 40 percent in "exceptional" drought according to the U.S. Drought Monitor.

U.S. Drought Monitor

California

July 28, 2015

(Released Thursday, Jul. 30, 2015)

Valid 8 a.m. EDT

Drought Conditions (Percent Area)

	None	D0-D4	D1-D4	D2-D4	D3-D4	D4
Current	0.14	99.86	97.35	94.59	71.08	46.00
Last Week 7/21/2015	0.14	99.86	97.35	94.59	71.08	46.00
3 Months Ago 4/28/2015	0.14	99.86	98.11	93.44	66.60	46.77
Start of Calendar Year 12/30/2014	0.00	100.00	98.12	94.34	77.94	32.21
Start of Water Year 9/30/2014	0.00	100.00	100.00	95.04	81.92	58.41
One Year Ago 7/29/2014	0.00	100.00	100.00	100.00	81.89	58.41

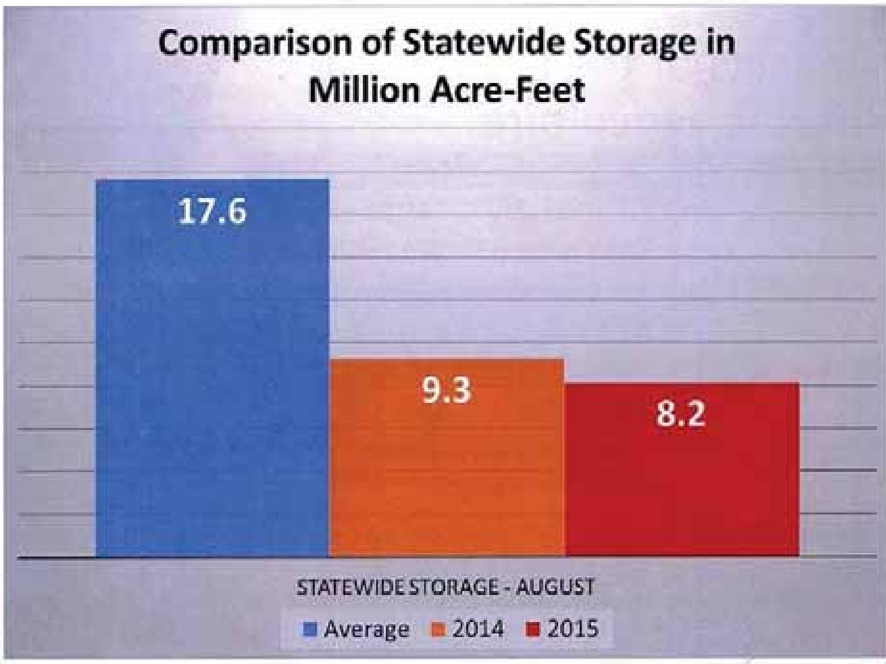
Intensity:

- D0 Abnormally Dry
- D1 Moderate Drought
- D2 Severe Drought
- D3 Extreme Drought
- D4 Exceptional Drought

The Drought Monitor focuses on broad-scale conditions. Local conditions may vary. See accompanying text summary for forecast statements.

Author:
Richard Heim
NCEI/NOAA

http://droughtmonitor.unl.edu/

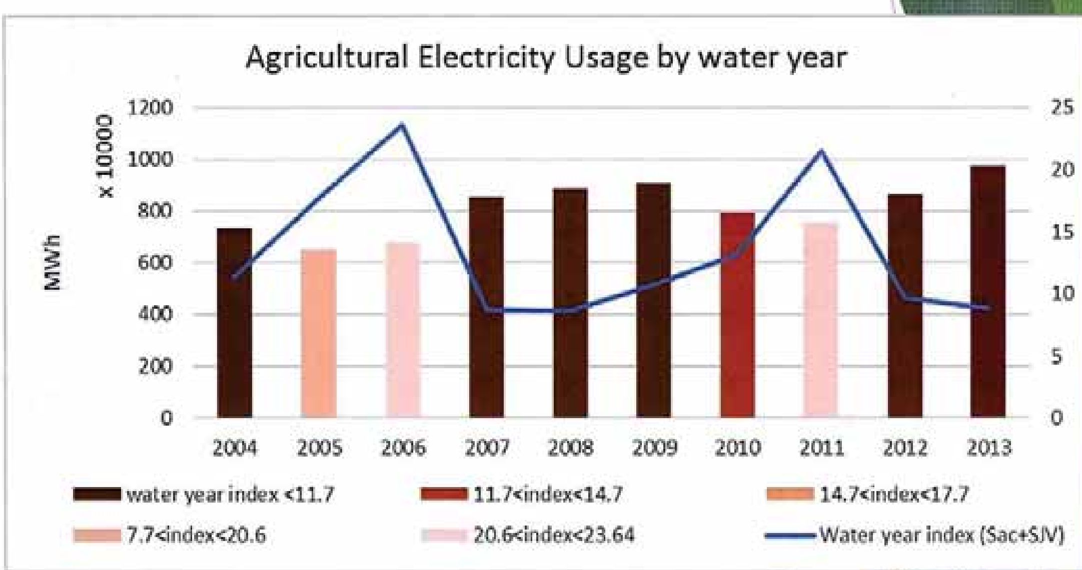


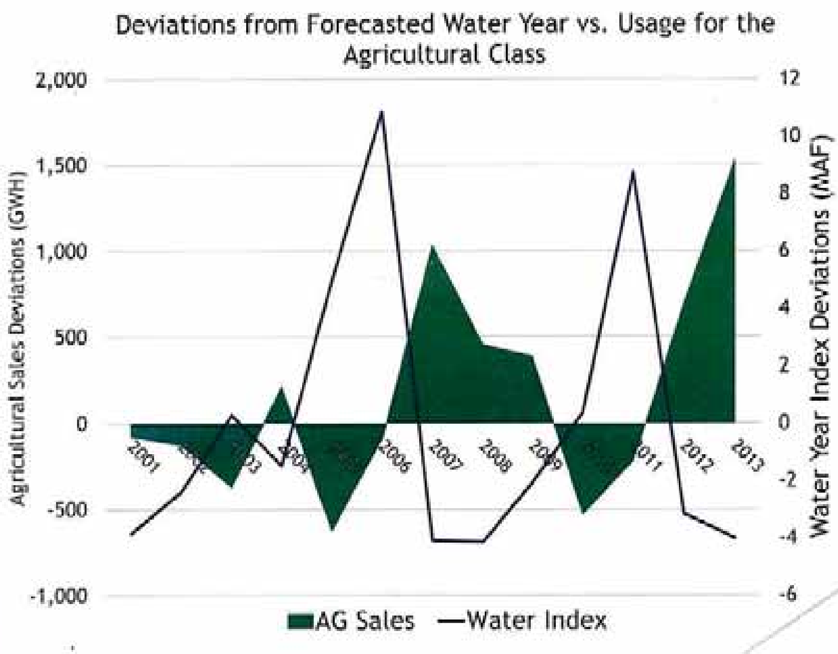
Economic impacts of the drought on California agriculture

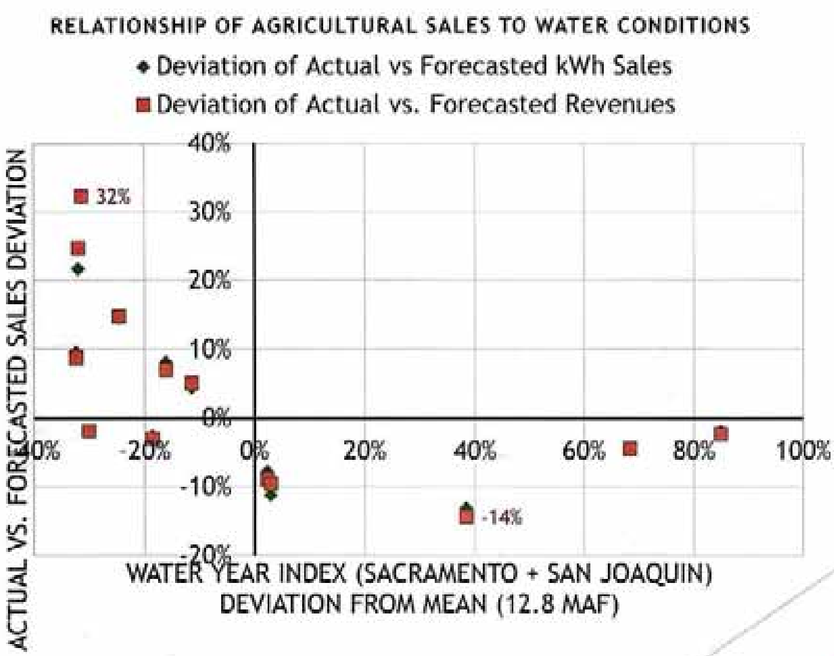
Statewide Costs	2014	2015
Crop revenue loss	$810 million	$850 million
Additional pumping cost	**$454 million**	**$600 million**
Livestock and dairy revenue loss	$203 million	$350 million
Total direct loss	$1.5 billion	$1.8 billion
total economic cost	$2.2 billion	$2.7 billion
total job losses	17,100	18,600
Size of statewide agricultural revenues (2012 $)	$48 billion	
Howitt, R.E., Medellin-Azuara, J., MacEwan, D., Lund, J.R. and Sumner, D.A. (2014).		

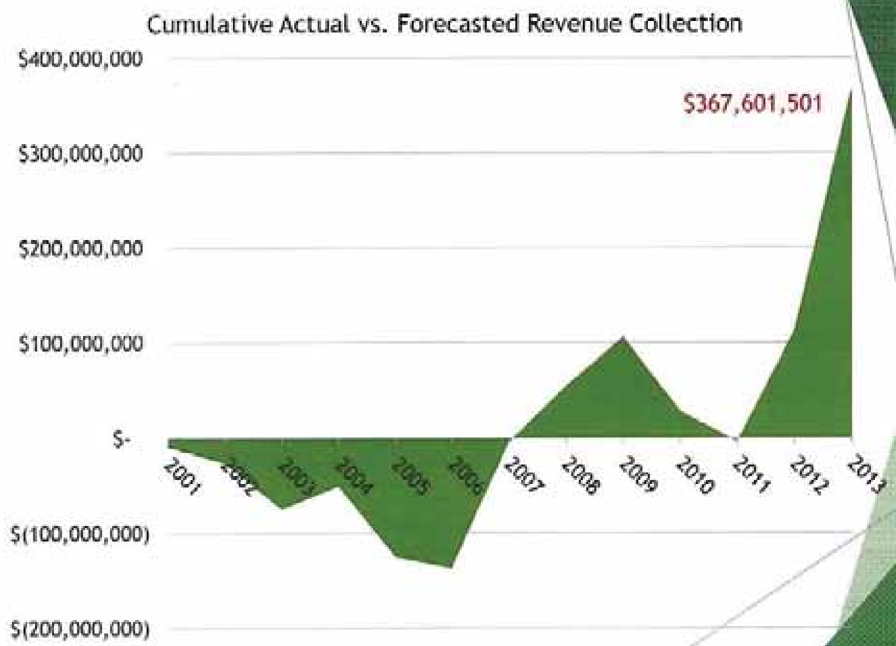
Agricultural Class Statistics

- Average annual kWh usage for 2001-13 = 4,750 GWH
- Average annual revenues for 2001-13 = $635 million
- Average water year index = 12.8 MAF




Deviations from Forecasted Water Year vs. Usage for the Agricultural Class
Agricultural Sales Deviations (GWH)
Water Year Index Deviations (MAF)
2,000
1,500
1,000
500
0
-500
-1,000
12
10
8
6
4
2
0
-2
-4
-6
2001
2003
2006
2007
2008
2011
2012
2013
AG Sales
Water Index


RELATIONSHIP OF AGRICULTURAL SALES TO WATER CONDITIONS
Deviation of Actual vs Forecasted kWh Sales
Deviation of Actual vs. Forecasted Revenues
ACTUAL VS. FORECASTED SALES DEVIATION
40%
30%
20%
10%
0%
-10%
-20%
32%
-14%
-40%
-20%
0%
20%
40%
60%
80%
100%
WATER YEAR INDEX (SACRAMENTO + SAN JOAQUIN)
DEVIATION FROM MEAN (12.8 MAF)



Possible Solutions

- Retrospective balancing account with other rate groups with cumulative accumulation deadbands.
- Rate surcharge to prepay reserve funds for agriculture and for other rate groups to repay.
- No obvious forecasting solution.
- Other ideas?

Data Required for Analysis

- Last 10 years of data (2005-2014) in order to provide for a long enough period to include various types of water and economic conditions while keeping the data collection and analysis manageable.
- The data needed for the analysis are as follows:
  - Hydrologic traces (i.e., annual water flows) for the major river basins (e.g. Four Rivers Index published by California Department of Water Resources);
  - Rainfall totals, comparable with those used PG&E's load forecasting model;
  - Forecasted kilowatt-hour (kWh) sales (total and bundled) adopted for each customer class in each GRC proceeding over the relevant period;
  - Forecasted kilowatt-hour (kWh) sales (total and bundled) adopted for each customer class in each ERRA proceeding over the relevant period;
  - Forecasted electric rate revenues adopted for each customer class and for the system total in each GRC Phase II proceeding over the relevant period, with generation and non-generation revenue requirements separately shown;
  - Actual kWh sales for each customer class in each year;
  - Actual electric rate revenues for each customer class in each year; and
  - Total system electric revenue requirement adopted for each year (in the Annual Electric True-Up or its equivalent), with ERRA generation and non-ERRA generation revenue requirements separately shown.

M.CUBED

Agricultural Class Balancing Account Study

PG&E

Workshop 1
September 22, 2015

Today's Agenda

Time	Topic/Action
10:00 am	Introductions
10:15 am	Study Objectives
10:30 am	Schedule
10:45 am	Data Requests and Sales Review
11:15 am	Studies
12:00 am	Next Steps

Overview of Study Objectives

Develop analysis to examine the desirability of a **balancing account** that addresses the **high level of sales variability** and **sales forecast uncertainty** pertaining to the **agricultural class**.

Such analyses would review:

- **year-to-year volatility of agricultural class revenues and sales** versus other customer class revenues and sales,

  and include

- **an assessment of possible over-collection of agricultural class revenue that accounts for variation** in both PG&E's **cost of service** and **revenues collected** due to agricultural sales variability.

Study Schedule

	Planned	Completed	Comment
Data Inquiry		3/25/2015	1st quarter
Provide Data AG Parties	9/8/2015	9/4/2015	2 weeks prior to workshop
Provide Data CLECA	9/8/2015	9/11/2015	2 weeks prior to workshop
1st Workshop		9/22/2015	By 9/24/2015
Draft Report	By 10/30/2015		5 months prior to filing GRC Phase II
2nd Workshop	On or after 11/16/2015		No less than 2 weeks following the draft report
Comments Due	By 12/11/2015		6 weeks following draft report
Completion of Report	By 12/30/2015		3 months prior to filing GRC II
Report Filed	3/31/2016		With GRC II filing

4

Data Requests

AG Parties:

The Agricultural Parties recommend using
the **last 10 years** of data (2005-2014)
in order to provide for a long enough period to include
various types of water and economic conditions
while keeping the data collection and analysis manageable.

Data needed for the analysis:

1) **Hydrologic traces** (i.e., annual water flows) for the major river basins (e.g. Four Rivers Index published by California Department of Water Resources);

2) **Rainfall totals**, comparable with those used PG&E's load forecasting model;

3) **Forecasted kilowatt-hour (kWh) sales (total and bundled)** adopted for each customer class in each GRC proceeding over the relevant period;

4) **Forecasted kilowatt-hour (kWh) sales (total and bundled)** adopted for each customer class in each ERRA proceeding over the relevant period;

5

Data Requests - Continued

AG Parties (continued)

5) **Forecasted electric rate revenues** adopted for each customer class and for the system total in each GRC Phase II proceeding over the relevant period, with generation and non-generation revenue requirements separately shown;

6) **Actual kWh sales** for each customer class in each year;

7) **Actual electric rate revenue**s for each customer class in each year; and

8) **Total system electric revenue requirement** adopted for each year (in the Annual Electric True-Up or its equivalent), with ERRA generation and non-ERRA generation revenue requirements separately shown.

6

Data Requests – Continued

CLECA

CLECA believes that the comparison should be made **over a long period (20 years)** to take into account variations due to business cycles as well as weather cycles.

CLECA notes that PG&E's FERC Form 1, page 304, states the recorded sales and revenues by rate schedule.

CLECA proposes that PG&E compile 20 years of Form 1 data by rate schedule and for the same period produce the annual ERRA, or previously, ECAC forecasts for each customer class.

With this set of data, CLECA would like to be able to see what kind of year-to-year variation occurs for each schedule over a long period.

CLECA would also be able to compare the recorded data to the forecast data, at least by customer class, so as to indicate the degree of forecast error that might be occurring.

7

Sales Review

Year	Actual (GWh)				Forecast (GWh)				% Variance			
	Res	Coml	Ind	AG	Res	Coml	Ind	AG	Res	Coml	Ind	AG
1995	24,391	26,742	16,665	3,478	24,845	27,508	17,467	3,803	-1.8%	-2.8%	-4.6%	-8.5%
1996	25,458	27,595	15,647	3,631	24,946	27,704	17,367	3,548	2.1%	-0.4%	-9.9%	2.4%
1997	25,946	28,775	16,824	3,932	25,457	27,844	17,678	3,758	1.9%	3.3%	-4.8%	4.6%
1998	26,846	28,810	16,290	3,069	26,535	28,399	17,611	3,743	1.2%	1.4%	-7.5%	-18.0%
1999	27,739	30,391	16,676	3,739	26,850	28,867	17,380	3,549	3.3%	5.3%	-4.1%	5.4%
2000	28,753	31,729	16,804	3,818	27,197	29,367	17,568	3,530	5.7%	8.0%	-4.3%	8.2%
2001	26,920	30,931	16,724	4,150	28,848	31,805	17,223	3,423	-6.7%	-2.7%	-2.9%	21.2%
2002	27,353	30,720	13,327	3,930	26,445	29,833	15,704	3,360	3.4%	3.0%	-15.1%	17.0%
2003	29,025	31,888	14,653	3,909	27,405	30,981	15,874	3,798	5.9%	2.9%	-7.7%	2.9%
2004	29,452	32,267	14,796	4,301	28,511	31,759	15,190	3,995	3.3%	1.6%	-2.6%	7.7%
2005	29,752	32,375	14,931	3,742	29,159	32,456	15,280	4,005	2.0%	-0.2%	-2.3%	-6.6%
2006	31,013	33,492	15,165	3,838	30,054	33,616	15,249	3,915	3.2%	-0.4%	-0.5%	-2.0%
2007	30,797	33,984	15,158	5,403	31,026	33,156	15,072	4,652	-0.7%	2.5%	0.6%	16.1%
2008	31,454	34,053	16,148	5,594	31,558	33,642	15,479	4,285	-0.3%	1.2%	4.3%	30.6%
2009	31,235	32,958	14,806	5,803	31,927	34,975	15,834	4,430	-2.2%	-5.8%	-6.5%	31.0%
2010	30,744	32,862	14,415	5,071	30,856	33,648	15,458	5,081	-0.4%	-2.3%	-6.7%	-0.2%
2011	30,872	32,841	14,497	4,691	31,173	33,914	14,639	5,163	-1.0%	-3.2%	-1.0%	-9.1%
2012	31,082	32,680	15,353	6,179	32,092	33,028	15,045	5,239	-3.1%	-1.1%	2.0%	17.9%
2013	30,990	32,732	14,958	7,022	32,126	32,538	15,000	5,045	-3.5%	0.6%	-0.3%	39.2%
2014	29,835	32,431	15,648	7,611	31,807	33,658	14,550	5,807	-6.2%	-3.6%	7.6%	31.0%

Examine Rate Changes

Examine the methods used to implement rate changes for revenue requirement changes

- Compare recorded and forecast billing determinants.
- Determine the impact on revenue allocation and total rates for different billing determinant assumptions

Cost of Service

Develop an assessment of possible over-collection of agricultural class revenue that accounts for variation in both PG&E's cost of service and revenues collected due to agricultural sales variability.

Simulate revenue allocation if forecast assumptions were perfect in the context of GRC II.

- **Select low and high year**. For example, 2008, 2009, 2013 and 2014 were under-forecast. 2005 and 2011 were over-forecast.
- **Develop revenue allocation based on standard costing.**
- **Develop revenue allocation using perfect assumptions** (for example, PCAF in 2009 would be actual PCAF in 2009 rather than an average of 3 prior years).
- **Compare resulting cost of service and results**

Thank You

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

ATTACHMENT 4

SALES AND AVERAGE RATE VARIABILITY

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
ATTACHMENT 4
SALES AND AVERAGE RATE VARIABILITY

TABLE 1
PG&E FORECAST VERSUS ACTUAL SALES
1995-2014

	Actual (MWh)				Forecast (MWh)				% Variance			
Year	Residential	Commercial	Industrial	Agricultural	Residential	Commercial	Industrial	Agricultural	Residential	Commercial	Industrial	Agricultural
1995	24,391,280	26,742,351	16,665,338	3,478,199	24,845,118	27,508,160	17,467,432	3,802,529	-1.8%	-2.8%	-4.6%	-8.5%
1996	25,457,707	27,594,793	15,646,645	3,631,376	24,945,988	27,704,021	17,366,722	3,547,899	2.1%	-0.4%	-9.9%	2.4%
1997	25,946,061	28,774,710	16,824,296	3,931,906	25,456,504	27,843,764	17,678,056	3,757,964	1.9%	3.3%	-4.8%	4.6%
1998	26,846,421	28,809,819	16,290,467	3,068,517	26,534,723	28,399,335	17,610,867	3,743,465	1.2%	1.4%	-7.5%	-18.0%
1999	27,739,169	30,390,763	16,675,970	3,739,442	26,850,000	28,866,876	17,379,973	3,548,800	3.3%	5.3%	-4.1%	5.4%
2000	28,753,363	31,729,382	16,804,099	3,818,471	27,197,000	29,367,173	17,568,251	3,529,600	5.7%	8.0%	-4.3%	8.2%
2001	26,919,816	30,931,499	16,724,388	4,149,637	28,847,627	31,804,732	17,223,393	3,422,874	-6.7%	-2.7%	-2.9%	21.2%
2002	27,352,506	30,720,415	13,327,035	3,930,434	26,445,320	29,832,977	15,703,947	3,359,508	3.4%	3.0%	-15.1%	17.0%
2003	29,024,571	31,888,262	14,652,572	3,908,761	27,404,692	30,981,227	15,874,291	3,797,826	5.9%	2.9%	-7.7%	2.9%
2004	29,451,812	32,267,463	14,795,824	4,300,632	28,510,914	31,758,572	15,189,790	3,994,756	3.3%	1.6%	-2.6%	7.7%
2005	29,752,492	32,375,350	14,931,163	3,742,178	29,158,534	32,455,548	15,279,718	4,005,422	2.0%	-0.2%	-2.3%	-6.6%
2006	31,013,224	33,492,219	15,165,406	3,838,454	30,054,360	33,615,827	15,249,018	3,915,100	3.2%	-0.4%	-0.5%	-2.0%
2007	30,797,140	33,984,106	15,158,490	5,402,882	31,026,230	33,156,218	15,072,109	4,652,438	-0.7%	2.5%	0.6%	16.1%
2008	31,454,145	34,053,289	16,147,954	5,594,023	31,558,385	33,641,785	15,478,901	4,284,896	-0.3%	1.2%	4.3%	30.6%
2009	31,234,681	32,958,064	14,805,543	5,803,346	31,926,840	34,974,822	15,834,106	4,429,911	-2.2%	-5.8%	-6.5%	31.0%
2010	30,744,336	32,862,310	14,414,954	5,070,535	30,856,068	33,648,340	15,458,127	5,081,483	-0.4%	-2.3%	-6.7%	-0.2%
2011	30,871,668	32,841,442	14,496,780	4,691,455	31,172,532	33,913,571	14,638,655	5,162,764	-1.0%	-3.2%	-1.0%	-9.1%
2012	31,082,050	32,679,971	15,352,774	6,178,539	32,091,672	33,028,374	15,045,456	5,238,918	-3.1%	-1.1%	2.0%	17.9%
2013	30,990,228	32,731,770	14,958,256	7,021,976	32,125,796	32,537,882	14,999,632	5,044,798	-3.5%	0.6%	-0.3%	39.2%
2014	29,835,314	32,431,217	15,648,127	7,610,559	31,806,532	33,657,833	14,549,585	5,807,472	-6.2%	-3.6%	7.6%	31.0%

Check	Recd Sales	Recd Sale ck	Total Forecast Sales	Total Forecast Sales Listed	Percent Listed of Total Forecast
1995	71,277,167	71,277,167	74,883,742	73,623,239	98.3%
1996	72,330,522	72,330,522	74,794,451	73,564,630	98.4%
1997	75,476,972	75,476,972	75,984,997	74,736,288	98.4%
1998	75,015,223	75,015,223	77,206,954	76,288,390	98.8%
1999	78,545,344	78,545,344	77,517,649	76,645,649	98.9%
2000	81,105,316	81,105,316	78,631,058	77,662,024	98.8%
2001	78,725,341	78,725,341	82,290,571	81,298,626	98.8%
2002	75,330,391	75,330,391	76,314,200	75,341,752	98.7%
2003	79,474,166	79,474,166	79,170,976	78,058,036	98.6%
2004	80,815,731	80,815,731	80,633,986	79,454,032	98.5%
2005	80,801,182	80,801,182	82,036,159	80,899,222	98.6%
2006	83,509,304	83,509,304	83,863,787	82,834,305	98.8%
2007	85,342,618	85,342,618	84,826,721	83,906,995	98.9%
2008	87,249,410	87,249,410	85,889,434	84,963,967	98.9%
2009	84,801,633	84,801,633	88,116,531	87,165,679	98.9%
2010	83,092,136	83,092,136	86,030,632	85,044,018	98.9%
2011	82,901,346	82,901,346	85,851,953	84,887,522	98.9%
2012	85,293,334	85,293,334	86,379,026	85,404,419	98.9%
2013	85,702,230	85,702,230	85,662,789	84,708,109	98.9%
2014	85,525,217	85,525,217	86,929,376	85,821,422	98.7%

Sales data not included in the table include revenue account 355 (streetlights), 356 (public authority), 357 (railway) and 360 (interdepartmental). The table includes residential sales (revenue account 350 and 351), commercial sales (revenue account 352 and 353), industrial sales (revenue account 359) and agricultural sales (revneue account 354). On a forecast basis, more than 98% of total sales are reflected in the table.

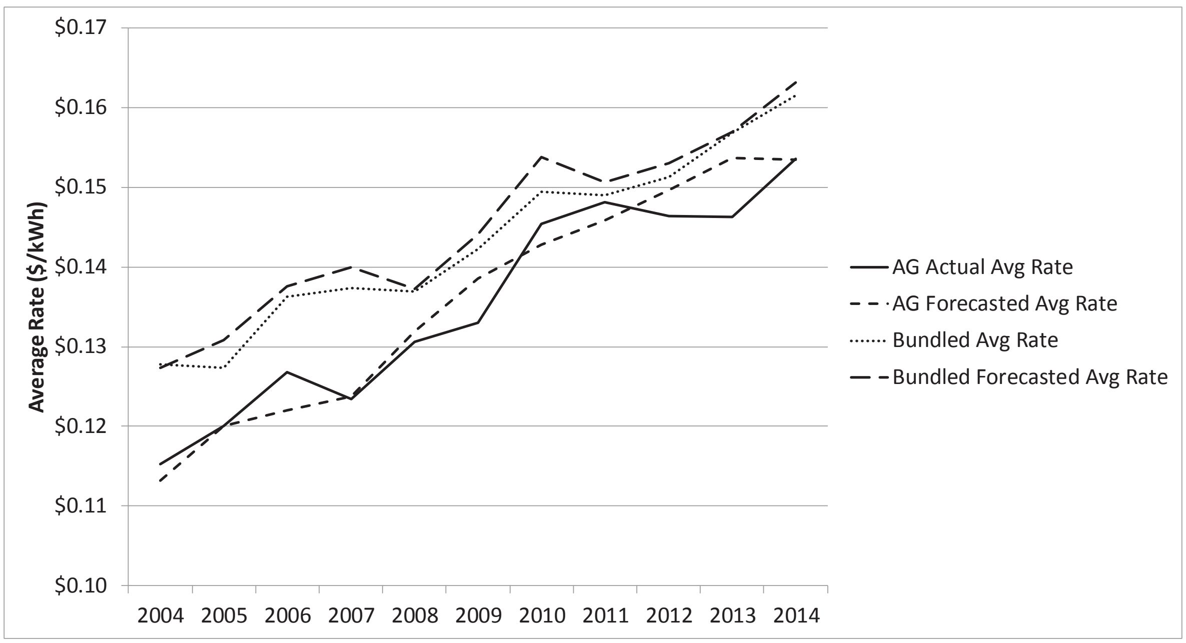
Forecast Sales Source

1995 A. 94-12-005 / Exhibit No. 6 / Table 4A-2 / Page 4A-9
1996 D.95-12-051
1997 D.96-12-080
1998 D.97-08-056
1999 A.97-12-020 / Exhibit No. 6 / Table 4A-1 (99 GRC Forecast)

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
ATTACHMENT 4
SALES AND AVERAGE RATE VARIABILITY
(Continued)

TABLE 2
PG&E FORECAST VERSUS ACTUAL AVERAGE AGRICULTURAL RATES
2004-2014

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
AG Actual Avg Rate	0.11522	0.12002	0.12682	0.12338	0.13058	0.13297	0.14545	0.14807	0.14634	0.14624	0.15363
AG Forecasted Avg Rate	0.11319	0.12006	0.12195	0.12374	0.13193	0.13850	0.14284	0.14581	0.14970	0.15364	0.15346
Bundled Avg Rate	0.12780	0.12737	0.13623	0.13735	0.13690	0.14228	0.14948	0.14904	0.15133	0.15689	0.16147
Bundled Forecasted Avg Rate	0.12729	0.13079	0.13761	0.13998	0.13721	0.14412	0.15383	0.15062	0.15304	0.15700	0.16313



PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
ATTACHMENT 4
SALES AND AVERAGE RATE VARIABILITY
(Continued)

TABLE 3
PG&E FORECAST VERSUS ACTUAL AVERAGE RATES BY CLASS
2005-2014

	2005			2006			2007			2008		
	Recorded	Forecast	Variance	Recorded	Forecast	Variance	Recorded	Forecast	Variance	Recorded	Forecast	Variance
Residential	$0.12914	$0.12892	0.2%	$0.14511	$0.14320	1.3%	$0.14935	$0.15157	-1.5%	$0.15034	$0.14897	0.9%
Small L&P	$0.14580	$0.15133	-3.7%	$0.15389	$0.15218	1.1%	$0.15833	$0.15964	-0.8%	$0.16199	$0.16124	0.5%
Medium L&P	$0.13907	$0.14366	-3.2%	$0.14373	$0.14434	-0.4%	$0.14338	$0.14458	-0.8%	$0.13954	$0.13845	0.8%
E19	$0.11708	$0.12944	-9.5%	$0.12166	$0.13153	-7.5%	$0.12106	$0.12888	-6.1%	$0.11861	$0.12047	-1.5%
Streetlights	$0.14930	$0.15219	-1.9%	$0.15996	$0.15865	0.8%	$0.16817	$0.17228	-2.4%	$0.15869	$0.15589	1.8%
Standby	$0.13020	$0.13700	-5.0%	$0.12527	$0.12622	-0.8%	$0.12460	$0.11461	8.7%	$0.11762	$0.12006	-2.0%
AG A	$0.18061	$0.20705	-12.8%	$0.19822	$0.21583	-8.2%	$0.19425	$0.23570	-17.6%	$0.20280	$0.21936	-7.5%
AG B/C	$0.11132	$0.11029	0.9%	$0.11678	$0.11140	4.8%	$0.11465	$0.11309	1.4%	$0.12204	$0.12278	-0.6%
AG Total	$0.12002	$0.12006	0.0%	$0.12682	$0.12195	4.0%	$0.12338	$0.12374	-0.3%	$0.13058	$0.13193	-1.0%
E20	$0.10220	$0.10741	-4.9%	$0.10293	$0.10880	-5.4%	$0.10046	$0.10208	-1.6%	$0.10027	$0.09954	0.7%
Total	$0.12737	$0.13079	-2.6%	$0.13623	$0.13761	-1.0%	$0.13735	$0.13998	-1.9%	$0.13690	$0.13721	-0.2%

	2009			2010			2011			2012		
	Recorded	Forecast	Variance	Recorded	Forecast	Variance	Recorded	Forecast	Variance	Recorded	Forecast	Variance
Residential	$0.15244	$0.15813	-3.6%	$0.15608	$0.16549	-5.7%	$0.15482	$0.15658	-1.1%	$0.15977	$0.16109	-0.8%
Small L&P	$0.16869	$0.16779	0.5%	$0.17970	$0.18118	-0.8%	$0.17855	$0.17831	0.1%	$0.18410	$0.18397	0.1%
Medium L&P	$0.14876	$0.14587	2.0%	$0.16210	$0.16055	1.0%	$0.15984	$0.15818	1.0%	$0.16056	$0.15904	1.0%
E19	$0.12656	$0.12546	0.9%	$0.13322	$0.13959	-4.6%	$0.13179	$0.13700	-3.8%	$0.13401	$0.13832	-3.1%
Streetlights	$0.15622	$0.16126	-3.1%	$0.16232	$0.16473	-1.5%	$0.16206	$0.16269	-0.4%	$0.16461	$0.16859	-2.4%
Standby	$0.13567	$0.12730	6.6%	$0.12786	$0.12279	4.1%	$0.12680	$0.12020	5.5%	$0.12969	$0.11881	9.2%
AG A	$0.21003	$0.23001	-8.7%	$0.23289	$0.23435	-0.6%	$0.23443	$0.24631	-4.8%	$0.23420	$0.26109	-10.3%
AG B/C	$0.12477	$0.12921	-3.4%	$0.13624	$0.13325	2.2%	$0.13856	$0.13634	1.6%	$0.13730	$0.14039	-2.2%
AG Total	$0.13297	$0.13850	-4.0%	$0.14545	$0.14284	1.8%	$0.14807	$0.14581	1.6%	$0.14634	$0.14970	-2.2%
E20	$0.10929	$0.10391	5.2%	$0.11633	$0.11518	1.0%	$0.11656	$0.11496	1.4%	$0.11315	$0.11414	-0.9%
Total	$0.14228	$0.14412	-1.3%	$0.14948	$0.15383	-2.8%	$0.14904	$0.15062	-1.0%	$0.15133	$0.15304	-1.1%

	2013			2014		
	Recorded	Forecast	Variance	Recorded	Forecast	Variance
Residential	$0.16527	$0.16529	0.0%	$0.16180	$0.17455	-7.3%
Small L&P	$0.19035	$0.18892	0.8%	$0.19992	$0.19406	3.0%
Medium L&P	$0.16672	$0.16625	0.3%	$0.17985	$0.17423	3.2%
E19	$0.14106	$0.14364	-1.8%	$0.15325	$0.14954	2.5%
Streetlights	$0.16732	$0.17483	-4.3%	$0.18487	$0.18100	2.1%
Standby	$0.13954	$0.11863	17.6%	$0.14715	$0.12830	14.7%
AG A	$0.22157	$0.24761	-10.5%	$0.23525	$0.24116	-2.4%
AG B/C	$0.13857	$0.14425	-3.9%	$0.14607	$0.14481	0.9%
AG Total	$0.14624	$0.15364	-4.8%	$0.15363	$0.15346	0.1%
E20	$0.11847	$0.11883	-0.3%	$0.12789	$0.12148	5.3%
Total	$0.15689	$0.15700	-0.1%	$0.16147	$0.16313	-1.0%

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

ATTACHMENT 5

GENERATION COST OF SERVICE

Pacific Gas & Electric Company

2017 GRC - Phase II

Balancing Account Study (using 2014 GENERATION Marginal Costs for all 4 years)

TABLE 1 - Attachment 5

Year	Customer Class	Generation Cost of Service: Actual Bundled Sales	Average Capacity MC	Average Energy MC	Total Average MC	Total MC Revenue	MC Revenue Share	PCAF	System PCAF Share	kWh/kW	Actual Billed Revenue	Actual Billed Rate	Allocated Billed Revenue	Allocated Billed Rate	Revenue Difference (Bill - Allocated)	Average Rate Difference
		(GWh)	($/kWh)	($/kWh)	($/kWh)	($M)	(%)	(MW)	(%)	(hrs)	($M)	($/kWh)	($M)	($/kWh)	($M)	(%)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	Calculation:	Recorded	= MC x Rec (9)	= MC x Rec (3)	= (4) + (5)	= (3) x (6)	= (7) / Total	Recorded	= (9) / Total	= (3) / (9)	Recorded	= (12) / (3)	= (8) x (12)	= (14 / (3)	= (12) - (14)	={ (13) - (15) } / (15)
2011	Residential	30,729	0.01654	0.04615	0.06269	1,926	41.40%	7,096	42.05%	4,330	2,340	0.07616	2,419	0.07873	-79	-3.27%
	Small L&P (incl. Streetlgts)	9,072	0.01411	0.04697	0.06108	554	11.91%	1,787	10.59%	5,077	608	0.06701	696	0.07671	-88	-12.64%
	Medium L&P	8,709	0.01708	0.04729	0.06437	561	12.05%	2,077	12.31%	4,193	949	0.10892	704	0.08085	244	34.72%
	Agriculture	**4,654**	**0.01854**	**0.04520**	**0.06373**	**297**	**6.37%**	**1,259**	**7.46%**	**3,696**	**334**	**0.07173**	**372**	**0.08005**	**-39**	**-10.38%**
	E-19	11,767	0.01513	0.04626	0.06139	722	15.53%	2,494	14.78%	4,719	837	0.07112	907	0.07710	-70	-7.75%
	E-20 (incl. Stdby)	10,152	0.01439	0.04398	0.05837	593	12.74%	2,162	12.81%	4,694	776	0.07642	744	0.07331	32	4.25%
	Total	75,082	0.01592	0.04605	0.06197	4,653	100.00%	16,875	100.00%	4,449	5,843	0.07783	5,843	0.07783	0	0.00%
2012	Residential	30,776	0.01601	0.04614	0.06215	1,913	40.87%	6,879	41.83%	4,474	2,093	0.06801	2,266	0.07363	-173	-7.64%
	Small L&P (incl. Streetlgts)	9,114	0.01272	0.04687	0.05959	543	11.60%	1,618	9.84%	5,633	585	0.06417	643	0.07060	-59	-9.10%
	Medium L&P	8,464	0.01619	0.04727	0.06346	537	11.48%	1,914	11.64%	4,422	778	0.09186	636	0.07519	141	22.18%
	Agriculture	**6,140**	**0.01711**	**0.04517**	**0.06228**	**382**	**8.17%**	**1,532**	**9.32%**	**4,007**	**425**	**0.06922**	**453**	**0.07379**	**-28**	**-6.18%**
	E-19	11,282	0.01500	0.04619	0.06119	690	14.75%	2,372	14.42%	4,757	923	0.08182	818	0.07250	105	12.86%
	E-20 (incl. Stdby)	10,739	0.01338	0.04384	0.05723	615	13.13%	2,131	12.96%	5,040	742	0.06906	728	0.06781	13	1.85%
	Total	76,516	0.01521	0.04596	0.06117	4,680	100.00%	16,446	100.00%	4,653	5,545	0.07247	5,545	0.07247	0	0.00%
2013	Residential	30,431	0.01957	0.04618	0.06575	2,001	42.08%	8,313	47.12%	3,661	2,541	0.08349	2,607	0.08567	-66	-2.54%
	Small L&P (incl. Streetlgts)	8,812	0.01273	0.04734	0.06007	529	11.13%	1,566	8.88%	5,626	599	0.06798	690	0.07826	-91	-13.14%
	Medium L&P	8,619	0.01576	0.04745	0.06321	545	11.46%	1,903	10.78%	4,530	836	0.09699	710	0.08236	126	17.77%
	Agriculture	**6,984**	**0.01434**	**0.04508**	**0.05942**	**415**	**8.73%**	**1,453**	**8.23%**	**4,808**	**502**	**0.07189**	**541**	**0.07742**	**-39**	**-7.14%**
	E-19	11,179	0.01442	0.04637	0.06079	680	14.29%	2,259	12.80%	4,950	957	0.08560	885	0.07920	72	8.08%
	E-20 (incl. Stdby)	9,980	0.01455	0.04405	0.05860	585	12.30%	2,148	12.18%	4,646	760	0.07611	762	0.07635	-2	-0.30%
	Total	76,005	0.01645	0.04611	0.06255	4,754	100.00%	17,641	100.00%	4,308	6,194	0.08150	6,194	0.08150	0	0.00%
2014	Residential	29,209	0.01759	0.04617	0.06377	1,863	40.34%	7,174	43.13%	4,071	2,682	0.09183	2,719	0.09308	-37	-1.34%
	Small L&P (incl. Streetlgts)	8,466	0.01347	0.04595	0.05942	503	10.90%	1,592	9.57%	5,317	631	0.07459	734	0.08674	-103	-14.01%
	Medium L&P	8,330	0.01590	0.04720	0.06309	526	11.38%	1,854	11.15%	4,493	751	0.09017	767	0.09210	-16	-2.10%
	Agriculture	**7,582**	**0.01422**	**0.04584**	**0.06006**	**455**	**9.86%**	**1,505**	**9.05%**	**5,037**	**601**	**0.07925**	**665**	**0.08768**	**-64**	**-9.61%**
	E-19	10,934	0.01465	0.04616	0.06081	665	14.40%	2,246	13.50%	4,869	1,242	0.11363	971	0.08877	272	28.01%
	E-20 (incl. Stdby)	10,330	0.01480	0.04383	0.05863	606	13.12%	2,261	13.59%	4,570	832	0.08051	884	0.08559	-52	-5.93%
	Total	74,850	0.01578	0.04590	0.06168	4,617	100.00%	16,632	100.00%	4,500	6,740	0.09004	6,740	0.09004	0	0.00%

Pacific Gas & Electric Company

2017 GRC - Phase II

Balancing Account Study (using 2011 GENERATION Marginal Costs for all 4 years)

TABLE 2 - Attachment 5

		Generation Cost of Service														
Year	Customer Class	Class Actual Bundled Sales	Average Capacity MC	Average Energy MC	Total Average MC	Total MC Revenue	MC Revenue Share	PCAF	System PCAF Share	kWh/kW	Actual Billed Revenue	Actual Billed Rate	Allocated Billed Revenue	Allocated Billed Rate	Revenue Difference (Bill - Allocated)	Average Rate Difference
		(GWh)	($/kWh)	($/kWh)	($/kWh)	($M)	(%)	(MW)	(%)	(hrs)	($M)	($/kWh)	($M)	($/kWh)	($M)	(%)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	Calculation:	Recorded	= MC x Rec (9)	= MC x Rec (3)	= (4) + (5)	= (3) x (6)	= (7) / Total	Recorded	= (9) / Total	= (3) / (9)	Recorded	= (12) / (3)	= (8) x (12)	= (14) / (3)	= (12) - (14)	={ (13) - (15) } / (15)
2011	Residential	30,729	0.02638	0.04216	0.06854	2,106	41.49%	7,096	42.05%	4,330	2,340	0.07616	2,424	0.07889	-84	-3.46%
	Small L&P (incl. Streetlgts)	9,072	0.02250	0.04297	0.06547	594	11.70%	1,787	10.59%	5,077	608	0.06701	684	0.07536	-76	-11.08%
	Medium L&P	8,709	0.02724	0.04330	0.07054	614	12.10%	2,077	12.31%	4,193	949	0.10892	707	0.08120	241	34.14%
	Agriculture	**4,654**	**0.02981**	**0.04159**	**0.07139**	**332**	**6.54%**	**1,259**	**7.46%**	**3,696**	**334**	**0.07173**	**382**	**0.08218**	**-49**	**-12.71%**
	E-19	11,767	0.02414	0.04235	0.06649	782	15.41%	2,494	14.78%	4,719	837	0.07112	901	0.07654	-64	-7.08%
	E-20 (incl. Stdby)	10,152	0.02313	0.04064	0.06377	647	12.75%	2,162	12.81%	4,694	776	0.07642	745	0.07341	31	4.11%
	Total	75,082	0.02543	0.04218	0.06761	5,076	100.00%	16,875	100.00%	4,449	5,843	0.07783	5,843	0.07783	0	0.00%
2012	Residential	30,776	0.02554	0.04214	0.06767	2,083	40.99%	6,879	41.83%	4,474	2,093	0.06801	2,273	0.07386	-180	-7.93%
	Small L&P (incl. Streetlgts)	9,114	0.02028	0.04287	0.06315	576	11.33%	1,618	9.84%	5,633	585	0.06417	628	0.06893	-43	-6.90%
	Medium L&P	8,464	0.02582	0.04327	0.06910	585	11.51%	1,914	11.64%	4,422	778	0.09186	638	0.07541	139	21.81%
	Agriculture	**6,140**	**0.02751**	**0.04156**	**0.06908**	**424**	**8.35%**	**1,532**	**9.32%**	**4,007**	**425**	**0.06922**	**463**	**0.07539**	**-38**	**-8.18%**
	E-19	11,282	0.02394	0.04227	0.06621	747	14.70%	2,372	14.42%	4,757	923	0.08182	815	0.07227	108	13.22%
	E-20 (incl. Stdby)	10,739	0.02151	0.04052	0.06204	666	13.11%	2,131	12.96%	5,040	742	0.06906	727	0.06771	14	1.99%
	Total	76,516	0.02430	0.04210	0.06640	5,081	100.00%	16,446	100.00%	4,653	5,545	0.07247	5,545	0.07247	0	0.00%
2013	Residential	30,431	0.03121	0.04222	0.07343	2,235	42.89%	8,313	47.12%	3,661	2,541	0.08349	2,657	0.08731	-116	-4.37%
	Small L&P (incl. Streetlgts)	8,812	0.02031	0.04334	0.06364	561	10.76%	1,566	8.88%	5,626	599	0.06798	667	0.07567	-68	-10.16%
	Medium L&P	8,619	0.02515	0.04348	0.06863	592	11.35%	1,903	10.78%	4,530	836	0.09699	703	0.08160	133	18.86%
	Agriculture	**6,984**	**0.02303**	**0.04155**	**0.06458**	**451**	**8.66%**	**1,453**	**8.23%**	**4,808**	**502**	**0.07189**	**536**	**0.07678**	**-34**	**-6.36%**
	E-19	11,179	0.02301	0.04248	0.06549	732	14.05%	2,259	12.80%	4,950	957	0.08560	870	0.07786	87	9.94%
	E-20 (incl. Stdby)	9,980	0.02338	0.04074	0.06412	640	12.28%	2,148	12.18%	4,646	760	0.07611	761	0.07624	-1	-0.17%
	Total	76,005	0.02627	0.04228	0.06855	5,210	100.00%	17,641	100.00%	4,308	6,194	0.08150	6,194	0.08150	0	0.00%
2014	Residential	29,209	0.02806	0.04218	0.07024	2,052	40.77%	7,174	43.13%	4,071	2,682	0.09183	2,748	0.09407	-65	-2.38%
	Small L&P (incl. Streetlgts)	8,466	0.02149	0.04200	0.06348	537	10.68%	1,592	9.57%	5,317	631	0.07459	720	0.08502	-88	-12.27%
	Medium L&P	8,330	0.02537	0.04319	0.06856	571	11.35%	1,854	11.15%	4,493	751	0.09017	765	0.09182	-14	-1.79%
	Agriculture	**7,582**	**0.02268**	**0.04203**	**0.06471**	**491**	**9.75%**	**1,505**	**9.05%**	**5,037**	**601**	**0.07925**	**657**	**0.08666**	**-56**	**-8.55%**
	E-19	10,934	0.02339	0.04224	0.06563	718	14.26%	2,246	13.50%	4,869	1,242	0.11363	961	0.08789	281	29.29%
	E-20 (incl. Stdby)	10,330	0.02378	0.04053	0.06431	664	13.20%	2,261	13.59%	4,570	832	0.08051	890	0.08612	-58	-6.52%
	Total	74,850	0.02520	0.04204	0.06724	5,033	100.00%	16,632	100.00%	4,500	6,740	0.09004	6,740	0.09004	0	0.00%

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

ATTACHMENT 6

DISTRIBUTION COST OF SERVICE

Pacific Gas & Electric Company
2017 GRC - Phase II
Balancing Account Study (using 2014 DISTRIBUTION Marginal Costs)

TABLE 1 - Attachment 6

		Distribution Cost of Service																
Year	Customer Class	Recorded Actual Bundled & DA/CCA Sales	Average Primary MC	Average Secondary & New Business Primary MC	Average Customer MC	Total Average MC	Total MC Revenue	MC Revenue Share	PCAF	System PCAF Share	FLT	Customer-months	Actual Billed Revenue	Actual Billed Rate	Allocated Billed Revenue	Allocated Billed Rate	Revenue Difference (Bill - Allocated)	Average Rate Difference
		(GWh)	($/kWh)	($/kWh)	($/kWh)	($/kWh)	($M)	(%)	(MW)	(%)	(MW)	(#)	($M)	($/kWh)	($M)	($/kWh)	($M)	(%)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
	Calculation:	Recorded	= MCRev / (3)	= MCRev / (3)	= MCRev / (3)	=(4)+(5)+(6)	= (7) x (3)	= (8) / (Total)	Recorded	= (10) / (Total)	Recorded	Recorded	Recorded	= (14) / (3)	= (9) x (Total 14)	= (16) / (3)	= (14) - (16)	=[(15)-(17)]/(17)
2011	Residential	30,872	0.01096	0.00668	0.01100	0.02864	884	49.46%	8,473	46.49%	14,131	55,252,818	1,945	0.06302	1,767	0.05723	179	10.11%
	Small L&P (incl. Streetlgts)	9,160	0.00898	0.00578	0.01653	0.03129	287	16.03%	1,819	9.98%	3,187	6,051,104	439	0.04788	573	0.06253	-134	-23.44%
	Medium L&P	9,486	0.00951	0.00550	0.00335	0.01836	174	9.74%	2,193	12.03%	3,697	593,745	431	0.04548	348	0.03668	83	23.98%
	Agriculture	**4,691**	**0.00925**	**0.00768**	**0.01335**	**0.03027**	**142**	**7.95%**	**1,530**	**8.39%**	**3,970**	**1,009,599**	**212**	**0.04521**	**284**	**0.06050**	**-72**	**-25.28%**
	E-19	14,726	0.00825	0.00382	0.00089	0.01297	191	10.68%	2,723	14.94%	3,686	211,280	354	0.02402	382	0.02591	-28	-7.31%
	E-20 (incl. Stdby)	14,641	0.00484	0.00208	0.00057	0.00749	110	6.13%	1,488	8.16%	2,161	14,466	191	0.01304	219	0.01497	-28	-12.85%
	Total	83,576	0.00893	0.00519	0.00726	0.02139	1,788	100.00%	18,226	100.00%	30,832	63,133,012	3,572	0.04274	3,572	0.04274	0	0.00%
2012	Residential	31,082	0.01130	0.00721	0.01098	0.02949	917	50.26%	7,198	45.71%	13,201	55,561,443	2,136	0.06872	2,016	0.06488	120	5.93%
	Small L&P (incl. Streetlgts)	9,267	0.00881	0.00593	0.01641	0.03114	289	15.82%	1,590	10.10%	2,922	6,073,891	486	0.05244	635	0.06851	-149	-23.46%
	Medium L&P	9,312	0.00921	0.00615	0.00342	0.01879	175	9.59%	1,897	12.05%	3,603	596,298	429	0.04608	385	0.04133	44	11.48%
	Agriculture	**6,179**	**0.00730**	**0.00669**	**0.01031**	**0.02431**	**150**	**8.24%**	**1,576**	**10.01%**	**3,718**	**1,027,533**	**281**	**0.04556**	**330**	**0.05349**	**-49**	**-14.82%**
	E-19	14,618	0.00772	0.00417	0.00090	0.01279	187	10.25%	2,281	14.49%	3,565	212,188	465	0.03178	411	0.02813	53	12.96%
	E-20 (incl. Stdby)	15,604	0.00431	0.00198	0.00054	0.00683	107	5.84%	1,204	7.65%	1,766	15,403	215	0.01380	234	0.01503	-19	-8.15%
	Total	86,062	0.00864	0.00546	0.00709	0.02119	1,824	100.00%	15,747	100.00%	28,775	63,486,756	4,012	0.04662	4,012	0.04662	0	0.00%
2013	Residential	30,990	0.01201	0.00676	0.01107	0.02983	924	40.68%	9,332	33.37%	13,914	55,827,699	2,144	0.06919	1,642	0.05297	503	30.62%
	Small L&P (incl. Streetlgts)	9,078	0.00793	0.00685	0.01676	0.03153	286	12.60%	1,720	6.15%	4,223	6,081,643	476	0.05242	508	0.05599	-32	-6.38%
	Medium L&P	9,499	0.00872	0.00598	0.01002	0.02472	235	10.33%	1,937	6.93%	3,987	596,588	421	0.04436	417	0.04389	5	1.09%
	Agriculture	**7,022**	**0.00823**	**0.00678**	**0.00907**	**0.02408**	**169**	**7.44%**	**1,616**	**5.78%**	**4,012**	**1,026,492**	**300**	**0.04270**	**300**	**0.04276**	**0**	**-0.13%**
	E-19	14,645	0.03545	0.00357	0.00222	0.04123	604	26.57%	12,800	45.77%	3,592	212,292	475	0.03244	1,072	0.07321	-597	-55.68%
	E-20 (incl. Stdby)	15,194	0.00109	0.00192	0.00055	0.00356	54	2.38%	560	2.00%	4,480	15,306	219	0.01440	96	0.00632	123	127.66%
	Total	86,428	0.01296	0.00529	0.00804	0.02629	2,273	100.00%	27,966	100.00%	34,207	63,760,020	4,035	0.04669	4,035	0.04669	0	0.00%
2014	Residential	29,835	0.01160	0.00714	0.01173	0.03047	909	49.01%	8,682	46.43%	14,111	56,151,146	1,534	0.05143	1,665	0.05581	-131	-7.85%
	Small L&P (incl. Streetlgts)	8,927	0.00894	0.00740	0.01722	0.03356	300	16.15%	1,905	10.19%	4,453	6,091,432	446	0.04993	549	0.06148	-103	-18.79%
	Medium L&P	9,388	0.01011	0.00588	0.00288	0.01887	177	9.55%	2,175	11.63%	3,597	500,851	354	0.03766	324	0.03456	29	8.98%
	Agriculture	**7,611**	**0.00961**	**0.00762**	**0.00902**	**0.02626**	**200**	**10.77%**	**1,760**	**9.41%**	**4,084**	**1,041,669**	**306**	**0.04020**	**366**	**0.04810**	**-60**	**-16.42%**
	E-19	14,585	0.00756	0.00355	0.00160	0.01272	185	10.00%	2,570	13.75%	3,591	321,016	539	0.03699	340	0.02329	200	58.81%
	E-20 (incl. Stdby)	15,897	0.00291	0.00182	0.00054	0.00528	84	4.52%	1,606	8.59%	4,444	15,459	219	0.01376	154	0.00966	65	42.39%
	Total	86,243	0.00870	0.00548	0.00732	0.02151	1,855	100.00%	18,698	100.00%	34,279	64,121,574	3,398	0.03940	3,398	0.03940	0	0.00%

Pacific Gas & Electric Company
2017 GRC - Phase II
Balancing Account Study (using DISTRIBUTION 2011 Marginal Costs)

TABLE 2 - Attachment 6

		Distribution Cost of Service																
Year	Customer Class	Recorded Actual Bundled & DA/CCA Sales	Average Primary MC	Average Secondary & New Business Primary MC	Average Customer MC	Total Average MC	Total MC Revenue	MC Revenue Share	PCAF	System PCAF Share	FLT	Customer-months	Actual Billed Revenue	Actual Billed Rate	Allocated Billed Revenue	Allocated Billed Rate	Revenue Difference (Bill - Allocated)	Average Rate Difference
		(GWh)	($/kWh)	($/kWh)	($/kWh)	($/kWh)	($M)	(%)	(MW)	(%)	(MW)	(#)	($M)	($/kWh)	($M)	($/kWh)	($M)	(%)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
	Calculation:	Recorded	= MCRev / (3)	= MCRev / (3)	= MCRev / (3)	=(4)+(5)+(6)	= (7) x (3)	= (8) / (Total)	Recorded	= (10) / (Total)	Recorded	Recorded	Recorded	= (14) / (3)	= (9) x (Total 14)	= (16) / (3)	= (14) - (16)	=[(15)-(17)]/(17)
2011	Residential	30,872	0.01560	0.00534	0.01368	0.03462	1,069	50.76%	8,473	46.49%	14,131	55,252,818	1,945	0.06302	1,813	0.05873	132	7.29%
	Small L&P (incl. Streetlgts)	9,160	0.01189	0.00472	0.02048	0.03709	340	16.13%	1,819	9.98%	3,187	6,051,104	439	0.04788	576	0.06292	-138	-23.91%
	Medium L&P	9,486	0.01188	0.00433	0.00503	0.02125	202	9.57%	2,193	12.03%	3,697	593,745	431	0.04548	342	0.03605	90	26.18%
	Agriculture	**4,691**	**0.01271**	**0.00631**	**0.01118**	**0.03020**	**142**	**6.73%**	**1,530**	**8.39%**	**3,970**	**1,009,599**	**212**	**0.04521**	**240**	**0.05123**	**-28**	**-11.76%**
	E-19	14,726	0.01023	0.00299	0.00238	0.01560	230	10.91%	2,723	14.94%	3,686	211,280	354	0.02402	390	0.02646	-36	-9.22%
	E-20 (incl. Stdby)	14,641	0.00554	0.00171	0.00123	0.00848	124	5.90%	1,488	8.16%	2,161	14,466	191	0.01304	211	0.01439	-20	-9.39%
	Total	83,576	0.01190	0.00416	0.00913	0.02519	2,106	100.00%	18,226	100.00%	30,832	63,133,012	3,572	0.04274	3,572	0.04274	0	0.00%
2012	Residential	31,082	0.01444	0.00580	0.01366	0.03390	1,054	49.41%	7,198	45.71%	13,201	55,561,443	2,136	0.06872	1,982	0.06378	154	7.75%
	Small L&P (incl. Streetlgts)	9,267	0.01181	0.00487	0.02032	0.03700	343	16.08%	1,590	10.10%	2,922	6,073,891	486	0.05244	645	0.06961	-159	-24.67%
	Medium L&P	9,312	0.01237	0.00511	0.00514	0.02262	211	9.88%	1,897	12.05%	3,603	596,298	429	0.04608	396	0.04257	33	8.26%
	Agriculture	**6,179**	**0.01016**	**0.00566**	**0.00864**	**0.02446**	**151**	**7.09%**	**1,576**	**10.01%**	**3,718**	**1,027,533**	**281**	**0.04556**	**284**	**0.04601**	**-3**	**-0.99%**
	E-19	14,618	0.01036	0.00355	0.00241	0.01632	239	11.18%	2,281	14.49%	3,565	212,188	465	0.03178	449	0.03070	16	3.52%
	E-20 (incl. Stdby)	15,604	0.00574	0.00181	0.00115	0.00870	136	6.37%	1,204	7.65%	1,766	15,403	215	0.01380	256	0.01638	-40	-15.71%
	Total	86,062	0.01136	0.00451	0.00892	0.02478	2,133	100.00%	15,747	100.00%	28,775	63,486,756	4,012	0.04662	4,012	0.04662	0	0.00%
2013	Residential	30,990	0.01780	0.00537	0.01377	0.03695	1,145	53.28%	9,471	50.29%	13,914	55,827,699	2,144	0.06919	2,150	0.06938	-6	-0.28%
	Small L&P (incl. Streetlgts)	9,078	0.01048	0.00566	0.02076	0.03689	335	15.59%	1,722	9.14%	4,223	6,081,643	476	0.05242	629	0.06928	-153	-24.33%
	Medium L&P	9,499	0.01117	0.00473	0.00505	0.02095	199	9.26%	2,083	11.06%	3,987	596,588	421	0.04436	374	0.03935	48	12.74%
	Agriculture	**7,022**	**0.01166**	**0.00553**	**0.00760**	**0.02479**	**174**	**8.10%**	**1,614**	**8.57%**	**4,012**	**1,026,492**	**300**	**0.04270**	**327**	**0.04656**	**-27**	**-8.28%**
	E-19	14,645	0.00875	0.00278	0.00240	0.01393	204	9.49%	2,453	13.02%	3,592	212,292	475	0.03244	383	0.02616	92	24.03%
	E-20 (incl. Stdby)	15,194	0.00329	0.00157	0.00118	0.00604	92	4.27%	1,491	7.92%	4,480	15,306	219	0.01440	172	0.01135	46	26.88%
	Total	86,428	0.01172	0.00424	0.00890	0.02486	2,149	100.00%	18,835	100.00%	34,207	63,760,020	4,035	0.04669	4,035	0.04669	0	0.00%
2014	Residential	29,835	0.01698	0.00575	0.01460	0.03733	1,114	45.37%	8,682	46.43%	14,111	56,151,146	1,534	0.05143	1,542	0.05167	-7	-0.47%
	Small L&P (incl. Streetlgts)	8,927	0.01185	0.00616	0.02168	0.03969	354	14.43%	1,905	10.19%	4,453	6,091,432	446	0.04993	490	0.05493	-45	-9.11%
	Medium L&P	9,388	0.01296	0.00477	0.00735	0.02508	235	9.59%	2,175	11.63%	3,597	500,851	354	0.03766	326	0.03471	28	8.50%
	Agriculture	**7,611**	**0.01343**	**0.00644**	**0.00725**	**0.02712**	**206**	**8.41%**	**1,760**	**9.41%**	**4,084**	**1,041,669**	**306**	**0.04020**	**286**	**0.03754**	**20**	**7.10%**
	E-19	14,585	0.00925	0.00283	0.01859	0.03067	447	18.22%	2,570	13.75%	3,591	321,016	539	0.03699	619	0.04245	-80	-12.87%
	E-20 (incl. Stdby)	15,897	0.00344	0.00152	0.00118	0.00614	98	3.98%	1,606	8.59%	4,444	15,459	219	0.01376	135	0.00850	84	61.86%
	Total	86,243	0.01190	0.00447	0.01210	0.02846	2,455	100.00%	18,698	100.00%	34,279	64,121,574	3,398	0.03940	3,398	0.03940	0	0.00%

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

ATTACHMENT 7

REVENUE ALLOCATION FOR OTHER COMPONENTS OF RATES (NUCLEAR DECOMMISSIONING)

Pacific Gas & Electric Company

2017 GRC - Phase II

Balancing Account Study (NON-BYPASSABLE CHARGES - Nuclear Decommissioning)

Attachment 7

		Nuclear Decommissioning Forecast Versus Actual						
Year	Customer Class	Forecast Bundled & DA/CCA Sales	Allocated Forecast Revenue	Actual Bundled & DA/CCA Sales	Reallocated Revenue based on Actual Sales	Actual Revenue	Revenue Difference in Actual vs Reallocated	Revenue Difference in Reallocated vs Forecast
		(GWh)	($M)	(GWh)	($M)	($M)	($M)	($M)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Calculation:	Forecast	Forecast	Recorded	= (5 Ratio) x (4 Total)	Actual	= (7) - (6)	= (6) - (4)
2011	ND Rate ($/kWh)		0.00066		0.00068	0.00066		
	Residential	31,316	20.6	30,872	21.0	20.4	-0.67	0.45
	Small L&P (incl. Streetlgts)	10,043	6.6	9,160	6.2	6.0	-0.20	-0.36
	Medium L&P	11,547	7.6	9,486	6.5	6.3	-0.21	-1.13
	Agriculture	**5,208**	**3.4**	**4,691**	**3.2**	**3.1**	**-0.10**	**-0.23**
	E-19	13,074	8.6	14,726	10.0	9.7	-0.32	1.44
	E-20 (incl. Stdby)	15,422	10.1	14,641	10.0	9.7	-0.32	-0.16
	Total	86,611	57.0	83,576	57.0	55.2	-1.82	0.00
2012	ND Rate ($/kWh)		0.00055		0.00055	0.00055		
	Residential	32,162	17.7	31,082	17.0	17.1	0.05	-0.64
	Small L&P (incl. Streetlgts)	9,351	5.1	9,267	5.1	5.1	0.01	-0.06
	Medium L&P	9,772	5.4	9,312	5.1	5.1	0.01	-0.27
	Agriculture	**5,283**	**2.9**	**6,179**	**3.4**	**3.4**	**0.01**	**0.48**
	E-19	14,640	8.1	14,618	8.0	8.0	0.02	-0.03
	E-20 (incl. Stdby)	15,832	8.7	15,604	8.6	8.6	0.02	-0.15
	Total	87,040	47.2	86,062	47.2	47.3	0.13	-0.66
2013	ND Rate ($/kWh)		0.00050		0.00050	0.00050		
	Residential	32,196	16.0	30,990	15.4	15.5	0.09	-0.62
	Small L&P (incl. Streetlgts)	9,007	4.5	9,078	4.5	4.5	0.03	0.03
	Medium L&P	10,402	5.2	9,499	4.7	4.7	0.03	-0.45
	Agriculture	**5,046**	**2.5**	**7,022**	**3.5**	**3.5**	**0.02**	**0.98**
	E-19	13,897	6.9	14,645	7.3	7.3	0.04	0.36
	E-20 (incl. Stdby)	15,783	7.9	15,194	7.6	7.6	0.04	-0.30
	Total	86,331	43.0	86,428	43.0	43.2	0.25	0.00
2014	ND Rate ($/kWh)		0.00049		0.00050	0.00049		
	Residential	32,196	15.8	29,835	14.8	14.6	-0.22	-0.94
	Small L&P (incl. Streetlgts)	9,007	4.4	8,927	4.4	4.4	-0.06	0.03
	Medium L&P	10,402	5.1	9,388	4.7	4.6	-0.07	-0.43
	Agriculture	**5,046**	**2.5**	**7,611**	**3.8**	**3.7**	**-0.06**	**1.31**
	E-19	13,897	6.8	14,585	7.3	7.1	-0.11	0.44
	E-20 (incl. Stdby)	15,783	7.7	15,897	7.9	7.8	-0.12	0.17
	Total	86,331	42.9	86,243	42.9	42.3	-0.63	0.58

ADDENDUM

TO APPENDIX F

AGRICULTURAL PARTIES Concluded PG&E's *Agricultural Class Balancing Account Study*, While Fundamentally Flawed, Confirms the Need for a Mechanism to Address Agricultural Sales Variability

Based on an examination of Pacific Gas and Electric Company's (PG&E) *Agricultural Class Balancing Account Study Report (Report)*, the Agricultural Parties – Agricultural Energy Consumers Association (AECA) and California Farm Bureau Federation (CFBF) – have concluded that the Report demonstrates that sales forecast error is a significant problem for the agricultural class, but that PG&E's revenue allocation analysis, which was meant to quantify the class-specific revenue impact of the sales forecast error, is sufficiently flawed as to render it meaningless.

The Agricultural Parties are deeply troubled by the numerous errors in PG&E's revenue allocation analysis and request that the analysis be withdrawn. Despite a request to PG&E to correct its load data, significant errors remain, along with analytical mistakes. In addition, the study addresses just a four-year period, substantially limiting its usefulness because it does not capture the full sequence of hydrologic conditions that lead to over-collection of revenues from agricultural customers. That said, the Report does effectively support the Agricultural Parties' earlier findings that there is significant variance, in many years, between PG&E's forecasted and actual loads for agricultural customers.

PG&E's Data and Analytical Errors Undermine its Revenue Allocation Analysis

PG&E undertook an elaborate analysis to calculate revenue allocations for the years 2011 to 2014, relying on its marginal costs from the 2011 and 2014 GRCs and actual customer loads, so as to compare a "perfect" revenue allocation to the adopted revenue allocation and actual customer revenue.[1] Unfortunately, PG&E's analysis is undermined by numerous data and analytical errors that affect key analytical elements, rendering it unreliable and its results meaningless.

Load Data Errors

Errors in PG&E's load data are evident from an examination of Attachments 5 and 6 to the PG&E Report, which present the underlying data for PG&E's revenue allocation analysis. The Actual Sales data in Column 3 of each table follow expected patterns of year-to-year variation. However, the same cannot be said for the generation PCAF (Peak Capacity Allocation Factor) data in Column 9 of Attachment 5, and

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[1] The Agricultural Parties do not believe such a short-term analysis is appropriate for addressing the question of whether, in the long-run, agricultural class load variability leads to a mis-assignment of revenue responsibility to the agricultural class. In PG&E's 2014 GRC Phase II, AECA submitted a revenue study as part of its testimony that covered the 2001 to 2013 period. The Agricultural Parties believe a longer-term study of that nature should be used to address the question of long-term revenue responsibility mis-assignment. However, in light of the significant errors in PG&E's analysis, questions of methodology are secondary to the significant data and analytical mistakes that render PG&E's analysis unreliable, and are not addressed further in these comments.

the distribution PCAF and Final Load Transformer (FLT) data in Columns 10 and 12 of Attachment 6.[2] PCAF and FLT loads are used to allocate generation capacity, primary distribution, secondary distribution, and distribution new business primary costs, and are therefore among the most important inputs to the revenue allocation study. Unfortunately, some of the trends evident from PG&E's PCAF and FLT datasets are simply not believable. For example:

- PCAF and FLT loads should have a fairly constant relationship to energy load, especially when averaged across a large number of customers; yet this is not always the case in PG&E's dataset. For example, from 2012 to 2013 the ratio of sales to FLT increases nearly 20% for the entire system (from 0.33 to 0.40) and rises 160% for E-20 and standby customers (from 0.11 to 0.29).
- Year-to-year load variations are much higher in PG&E's dataset than would be expected for large groups of customers. For example, the distribution PCAF varies from year-to-year by as much as 30% for residential customers;[3] the FLT, by as much as 44% for small L&P customers.[4] The significant load variation for these customer groups contrasts with even higher sales variation for agricultural customers in the same period. In other words, PCAF and FLT data patterns are contradicted by sales data patterns.
- The PCAF and FLT should generally move in lockstep; instead the relationships vary significantly across the years. For example, according to PG&E's data, the ratio of distribution PCAF to FLT for E-20 and standby customers was 0.68 in 2012 and 0.33 in 2013; the ratio of generation PCAF to FLT for this customer grouping fell from over 1.0 in 2011 and 2012 to around 0.5 in 2013 and 2014.
- Generation PCAFs should be no higher than distribution PCAFs, since generation PCAFs exclude direct access and Community Choice Aggregation loads that are included in distribution PCAFs; yet, in 2012, generation PCAFs in PG&E's dataset are higher than distribution PCAFs for seven of the nine customer classes, and for standby customers, generation PCAFs are more than 1,000 times higher than distribution PCAFs in 2013 and 2014.[5]

PG&E offers no explanation for these oddities, which, given their extreme nature, are reasonably viewed as errors unless evidence to the contrary is provided. The persistence of such mistakes is particularly disturbing in light of the fact that the release of PG&E's report was delayed from its original July deadline because of errors in this very data set that the Agricultural Parties brought to PG&E's attention. In other words, the dataset described above and used in PG&E's updated analysis was already corrected by PG&E and still appears to be so error-laden as to be unusable.

Given the many errors that persist in this dataset, it is evident that PG&E's fact-checking and correction processes have been grossly insufficient.[6] While intervenors can spot obvious data faults, the

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[2] PCAF is the sum of coincident peak loads for the class over a period that covers the highest system load hours; FLT is the sum of peak loads on the final line transformer for each customer. Distribution PCAFs include all customer load; generation PCAFs include only bundled customer load.

[3] Distribution PCAFs for residential customers are shown as 7,198 MW in 2012 and 9,471 MW in 2013 (Attachment 6, Table 2).

[4] FLTs for small L&P customers (including streetlights) are shown as 2,922 MW in 2012 and 4,223 MW in 2013 (Attachment 6, Table 2).

[5] Data from PG&E workpaper, "GRC comparison.xlsx," sheet "FLT & PCAF by Year," rows 3-16.

[6] There are additional mistakes in Attachment 6, Table 1, that appear to be typographical rather than errors with the data used in the analysis. For example, the E-19 distribution PCAF shown in Table 1 increases five-fold in 2013, then reverts back to more typical levels in 2014; however, it appears that the data used in PG&E's analysis differ in this case from the data shown in Table 1. (The errors described in the bulleted list above

Agricultural Parties do not have the information to do a thorough vetting without PG&E's assistance, nor do we have the necessary information to correct identifiable errors. Given that the Agricultural Parties have already attempted, unsuccessfully, to have PG&E review and correct its load data, and given that these erroneous data are key inputs to the revenue allocation calculations, we are in the untenable position of being cognizant of substantial errors without being able to offer possible curatives or identify a means to salvage the analysis. The Agricultural Parties conclude, therefore, that PG&E's results should be recognized as meaningless.

Analytical Errors

Given extensive errors in the load data used in the revenue allocation analysis, the Agricultural Parties did not conduct a thorough assessment of PG&E's study.[7] However, the limited assessment that we did conduct revealed additional material errors.

PG&E's revenue allocation analysis follows the utility's GRC Phase II revenue allocation approach, except that it uses actual loads for the years in question in place of a combination of historic loads from prior years and loads that were forecasted for that year. In other words, PG&E examined only a backcast of revenue requirements, instead of comparing that backcast to a forecast that would have been used in each GRC and ERRA to set rates.[8] Without such a comparison, it is impossible to determine to what extent revenue responsibilities fall out of balance. The section of analysis that the Agricultural Parties evaluated is the calculation of distribution primary, secondary, and new business revenue requirements.

In a typical GRC Phase II, PG&E calculates marginal costs for each of these cost elements and then assigns these costs to rate classes based on historic FLT and PCAF loads. PG&E divides the resulting revenue requirement for each rate class by historic sales to obtain per-kWh rates for each rate class, then multiplies these rates by a forecast of the sales for each rate class to obtain the revenue requirement forecast for each rate class. In other words, instead of assigning marginal costs to rate classes based on a forecast of FLT and PCAF loads, PG&E essentially assumes that the ratios of FLT to sales and of PCAF to sales will remain constant for each rate class, and calculates marginal cost responsibility based on historic FLT and PCAF loads, scaled for the difference between forecasted and historic sales.[9]

For the 2011-2014 analysis, PG&E has data on actual loads for each of the years in question; initial revenue responsibility can therefore be assigned directly by applying marginal costs to actual FLT and PCAF loads. PG&E's analysis does this step correctly, although the underlying data is questionable, but

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are associated with the data used in PG&E's analysis in workpaper, "GRC comparison.xlsx" and are not simply typographical errors in the report table.) In light of the other data issues identified, and PG&E's earlier correction of data errors in its report, the further errors in Table 1, even if they are simply typographical, are disconcerting, and further erode confidence in PG&E's Report.

[7] PG&E's workpapers for this Report include well more than 100 spreadsheet files; some of the links between files are not intact.

[8] The PG&E Report appears at first glance to compare the backcasted revenue requirements with the actual revenue requirements based on the GRC forecasts, but the data points being compared in PG&E's analysis are not truly comparable. For example, the backcasted revenue requirements are based on allocations derived from the GRC marginal costs, whereas the actual revenue requirements were based on allocations derived from the GRC marginal costs, adjusted for the adopted caps, and then further adjusted with annual ERRA rebalancing. For a meaningful comparison, the same analyses would need to be conducted to develop both the forward-looking and backcasted revenue allocations, with only the sales amounts differing from one analysis to the other.

[9] As seen in the data errors discussed in the previous section, this assumption of consistent relationships appears to be untrue in PG&E's dataset.

then proceeds with the remaining steps of the standard GRC Phase II process, meaning that after marginal costs are assigned based on actual FLT and PCAF loads, PG&E divides the resulting revenue requirements by actual sales, in place of historic sales, and then multiplies them by actual sales, in place of forecasted sales. These last two steps – dividing and then multiplying by actual sales – should cancel each other out, and the final revenue requirement should be the same as the initial revenue requirement obtained by assigning marginal costs to rate classes based on actual FLT and PCAF loads; however, on account of further analytical errors, this is not the case.

In the analysis reviewed, which uses 2014 GRC marginal costs with 2013 recorded data, there are numerous significant differences between the revenue requirements obtained after dividing and multiplying by actual sales ("final RRQ") and initial revenue responsibilities obtained from multiplying marginal costs by actual FLT and PCAF loads ("initial RRP"). For example, for distribution primary costs, the E-20-P final RRQ that are used in PG&E's Attachment 6 results tables are 45% lower than the initial RRP calculated for this customer class.[10] The reason for this difference is that the E-20-P initial RRP is divided by actual sales for both E-20-P and E-20-T customers to obtain a marginal cost rate, and then this rate is applied only to E-20-P actual sales, because transmission-level customers do not pay primary distribution costs. In other words, because the sales amount used to calculate the E-20-P rate is too high, because it erroneously includes E-20-T sales, the E-20-P rate is lower than needed to recover the E-20-P initial RRP, and the final RRQ is therefore lower than the actual E-20-P initial RRP. PG&E similarly included transmission-level kWh in calculating primary distribution rates for other classes, and included primary-level kWh in calculating secondary distribution rates. Since most non-secondary load is from large commercial and industrial customers, these mistakes result in an underestimate of cost responsibility for the large commercial and industrial customers.

There are additional errors, as well. A-10-P initial RRP is erroneously excluded from the calculation of initial RRP for Medium L&P customers.[11] The standby calculation uses Small L&P non-coincident peak load data from 2005-2007 instead of actual 2013 data, resulting in a final standby RR that is only 6% of the standby initial RRP for new business costs, and more than 500% of the standby initial RRP for primary and secondary distribution costs.[12]

Given the extent of errors identified and the Agricultural Parties' inability to develop corrected analyses without accurate load data, the Agricultural Parties did not take the time to evaluate the generation or other distribution revenue allocation calculations. It is clear from even the recognized data and analytical errors that PG&E's revenue allocation analysis should be dismissed as unreliable.

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[10] See PG&E workpaper "CONF_MCRev_GRC.xlsx" in folder Confidential Workpapers/GRC with actuals - all with 2014 MCs/2013 Actuals/AG Balancing Accounts Study - Model. For E-20-P customers, final RRQs are found in worksheet "MCR_Summary," cells B99:D99, and revenue responsibility is found in worksheet, "D_MCR_pkwh," cells B29:G29.

[11] See sheet, "D_MCR_pkwh": marginal cost rates for A-10 customers shown in J17-O17 are calculated by dividing A-10S marginal cost responsibility by the combined sales for A-10-S and A-10-P customers. The A-10-P cost responsibility is excluded from the final revenue requirement amounts.

[12] See workpaper, "Billing Determinants_GRC.xls," sheet "ForStandbyMCR," which is linked to sheet, "D_Stby_MCR" in the workpaper, "CONF_MCRev_GRC.xlsx."

PG&E’s Historic Sales Data Verifies that Agricultural Load Variability is a Significant Issue

While the key analysis in PG&E’s study, related to revenue allocation, is unreliable, there is one useful dataset in the Report: the dataset provided in Attachment 4, Table 1, which shows actual compared to forecasted sales for each major customer class from 1995 through 2014. A portion of this table is reproduced below, with the addition of a total line at the bottom that shows the difference over this 20-year period between actual and PG&E’s forecasted sales for each of these customer classes.

Inspection of the annual data shows that the variance between forecasted and actual sales is, on the whole, much greater for the agricultural class than for other customer classes. For residential and commercial customers, the variance did not exceed ±8.0% in any year in this period; for industrial customers, the variance exceeded ±8.0% in just two of the 20 years, with a peak variance of -15% in 2002. By contrast, for agricultural customers, the variance exceeded ±8.0% in 12 years (i.e., two-thirds of the period), exceeded ±16.0% in nine years, and even exceeded ±30.0% in four years, including a 39% variance in 2013 and a 31% variance in 2014.

Moreover, the Total line reveals that the under- and overestimates do not cancel each other out for agricultural customers, instead continuing to accumulate against the class. For residential and commercial customers, actual sales over the 20-year period were within a few tenths of a percent of forecasted sales; for industrial customers, actual sales were 3.5% below forecasted;, and for agricultural customers, actual sales were more than 10% above forecasted sales. If, as the Agricultural Parties maintain, years of higher-than-expected sales from a customer class tend to result in an overcollection of revenue requirement from the class due to the overcollection of fixed costs, and vice versa in years of lower-than-expected sales, then it is likely that PG&E has over-collected revenue from agricultural customers over this period. Given that actual agricultural sales were 18%-39% higher than forecasted sales in the 2012-2014 period, the overcollection of revenue from agricultural customers in recent years is likely particularly substantial.

Table 1: Actual Sales Compared to PG&E's Forecast

	Residential	Commercial	Industrial	Agricultural
1995	-1.8%	-2.8%	-4.6%	-8.5%
1996	2.1%	-0.4%	-9.9%	2.4%
1997	1.9%	3.3%	-4.8%	4.6%
1998	1.2%	1.4%	-7.5%	-18.0%
1999	3.3%	5.3%	-4.1%	5.4%
2000	5.7%	8.0%	-4.3%	8.2%
2001	-6.7%	-2.7%	-2.9%	21.2%
2002	3.4%	3.0%	-15.1%	17.0%
2003	5.9%	2.9%	-7.7%	2.9%
2004	3.3%	1.6%	-2.6%	7.7%
2005	2.0%	-0.2%	-2.3%	-6.6%
2006	3.2%	-0.4%	-0.5%	-2.0%
2007	-0.7%	2.5%	0.6%	16.1%
2008	-0.3%	1.2%	4.3%	30.6%
2009	-2.2%	-5.8%	-6.5%	31.0%
2010	-0.4%	-2.3%	-6.7%	-0.2%
2011	-1.0%	-3.2%	-1.0%	-9.1%
2012	-3.1%	-1.1%	2.0%	17.9%
2013	-3.5%	0.6%	-0.3%	39.2%
2014	-6.2%	-3.6%	7.6%	31.0%
1995-2014 Total	0.1%	0.2%	-3.5%	10.4%

Conclusions

PG&E's report confirms the Agricultural Parties' assertion that sales forecast error is a much more substantial problem for the agricultural class than for other customer classes, that under- and over-forecasting errors do not cancel each other out for agricultural customers, and that this is a timely problem that has been particularly significant in recent years. These results are not surprising, given that agricultural use of electricity is highly sensitive to water conditions that cannot be accurately predicted in advance, and that energy use in dry years is not fully offset by savings in wet years.

The Agricultural Parties do not fault PG&E for its difficulty in forecasting agricultural sales; rather, the Agricultural Parties continue to request that PG&E and the Commission acknowledge that precipitation and water allocation forecasts far more prescient and timely than presently available would be required to accurately forecast agricultural sales, and that PG&E cannot therefore be expected to accurately forecast these sales. Instead, a new mechanism should be developed to adjust the PG&E sales forecast and resulting revenue allocation after information is available on water allocations for the year or other information that would lead to a more reliable agricultural sales forecast. The Agricultural Parties will develop such a proposal in its testimony in the current GRC Phase II proceeding, and looks forward to working with PG&E and other parties to shape it into a solution that is workable and fair to all parties.

Regardless, PG&E's calculation of the revenue implications of sales forecast error is, unfortunately, critically flawed and should be withdrawn. However, revenue results are not needed to move forward.

Sales forecasts are key inputs to the revenue allocation study, and impact revenue allocation. Given the magnitude of the sales forecast errors[13] shown in the Table 1 data for the agricultural class, it is clear that these errors have influenced revenue allocations, creating some amount of cost over-recovery. It is reasonable to conclude that the amount of the impact is likely substantial. Parties do not need to agree on the amount of this effect to agree on an approach to improve the revenue allocation process to explicitly account for agricultural forecasting error, with the aim of more accurately assessing cost responsibility for all customer classes.

[13] We use the term "error" non-pejoratively in this case; these are unavoidable errors inherent from natural system variability. No amount of research or analysis can fix these "errors" ahead of time.